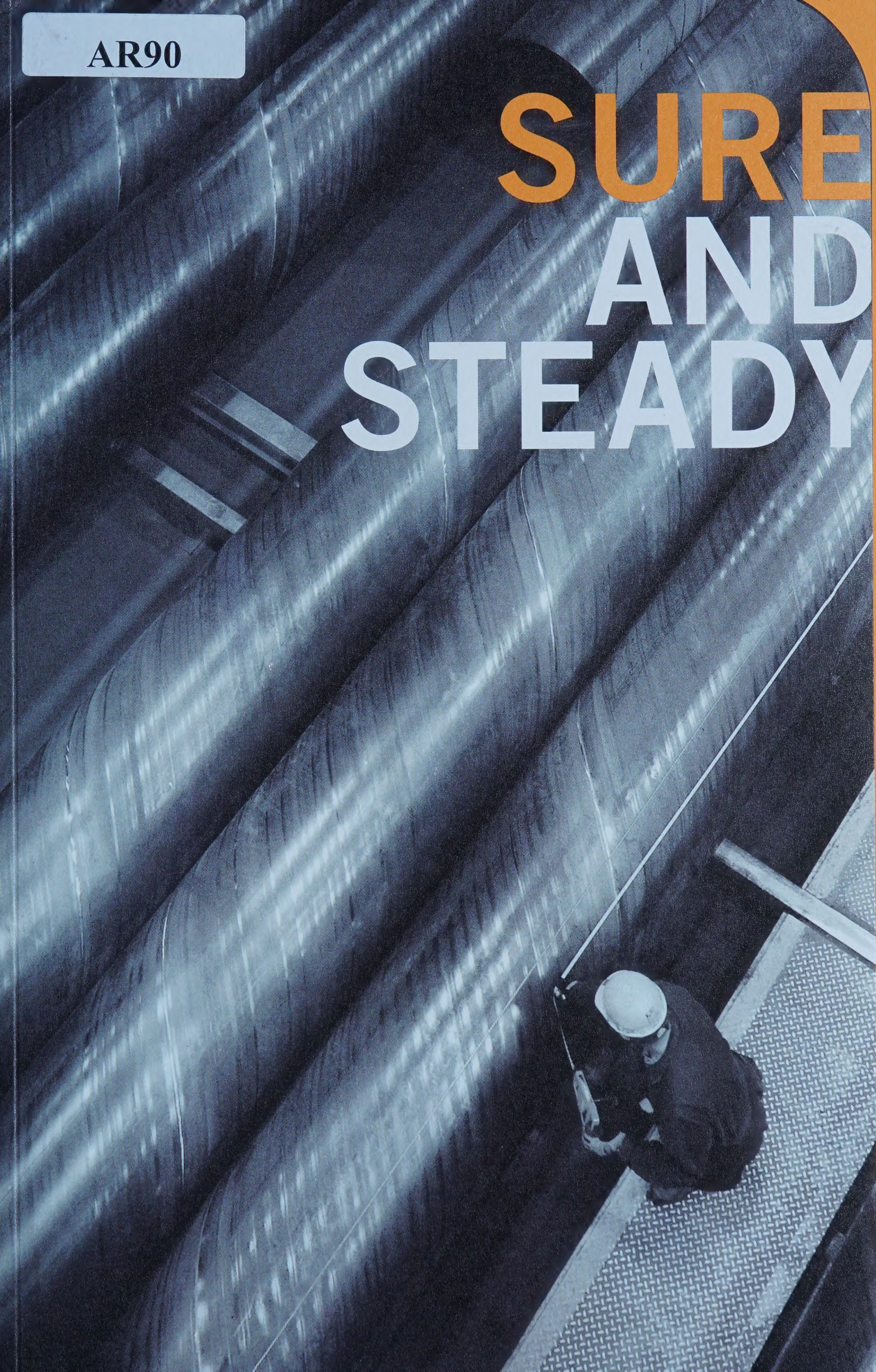


SURE AND STEADY

ENBRIDGE INC. 2008 ANNUAL REPORT


DELIVERING
VALUE

Safety. Income. Growth.

Our low-risk business model delivers steady income and visible, long-term growth.

We're well positioned financially and geographically to take advantage of the many growth opportunities before us.

That's Enbridge.

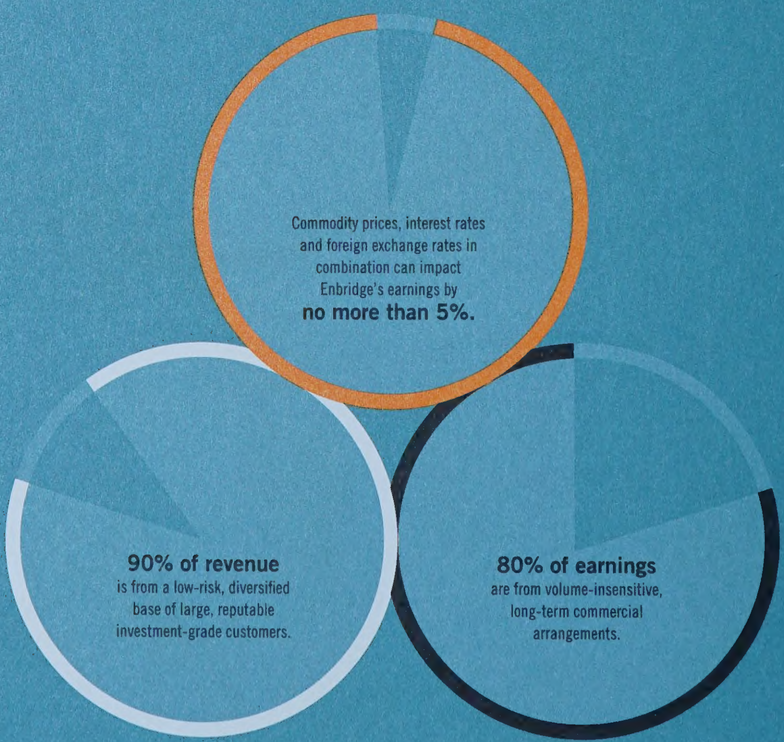
On the cover:
Over 99% of the pipes Enbridge will use in its expansion projects will be made from recycled steel.

Forward-looking Information: *This Annual Report includes references to forward-looking information. By its nature this information applies certain assumptions and expectations about future outcomes, so we remind you it is subject to risks and uncertainties that affect every business, including ours. The more significant factors and risks that might affect future outcomes for Enbridge are listed and discussed in the "Forward-looking Information" and risk sections of our public disclosure filings, including Management's Discussion & Analysis, available on both the SEDAR and EDGAR systems at www.sedar.com and www.sec.gov/edgar.shtml.*

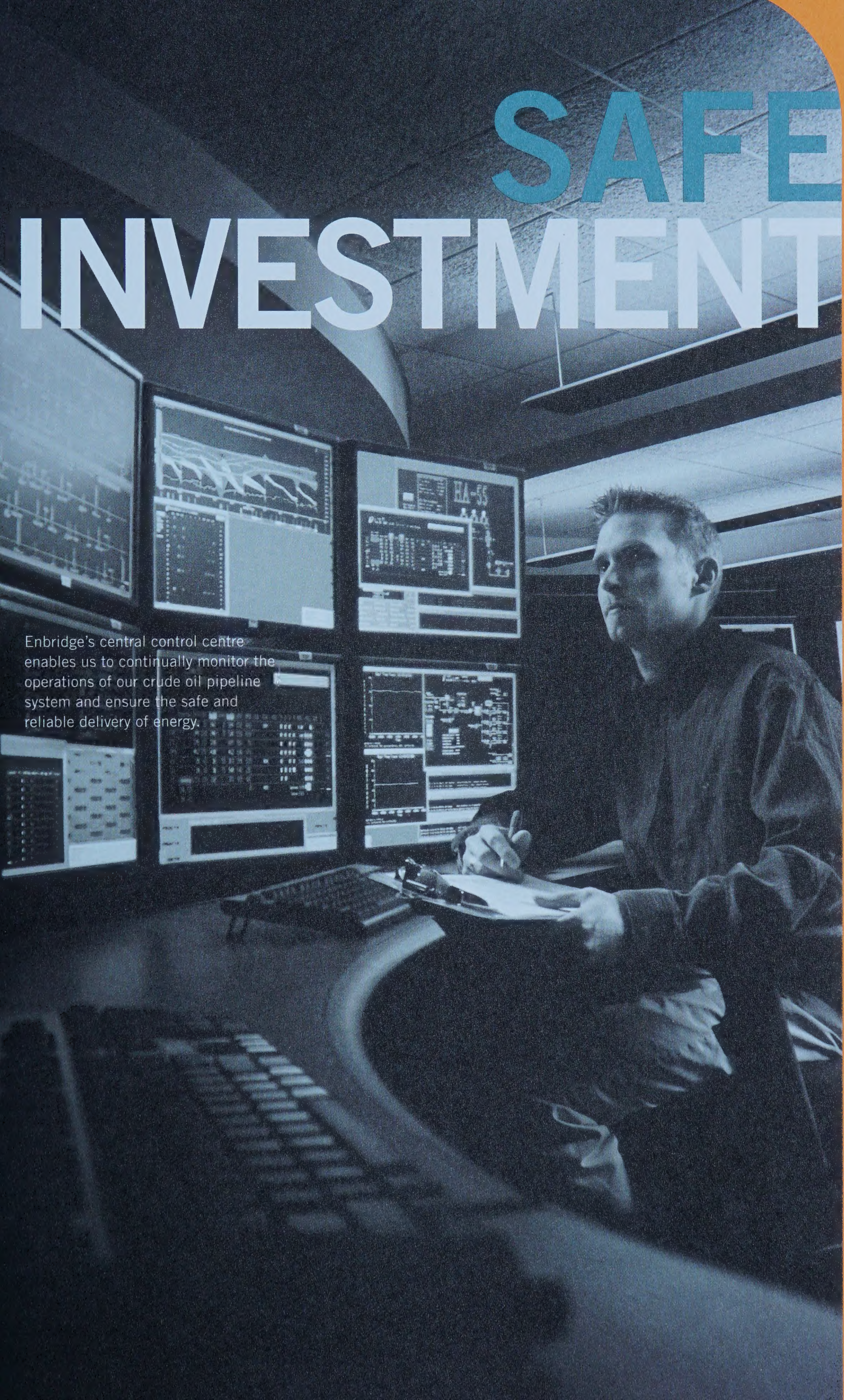
An investment in Enbridge is low risk.

We're managing risk.
From the capital cost of our growth projects, the volumes we're contracted to carry, and the creditworthiness of our customers to the impact of fluctuating commodity prices and foreign exchange and interest rates, our low-risk business model results in highly predictable earnings.

Low-risk Business Model



SAFE INVESTMENT



Enbridge's central control centre enables us to continually monitor the operations of our crude oil pipeline system and ensure the safe and reliable delivery of energy.

ENBRIDGE INC. 2008 ANNUAL REPORT

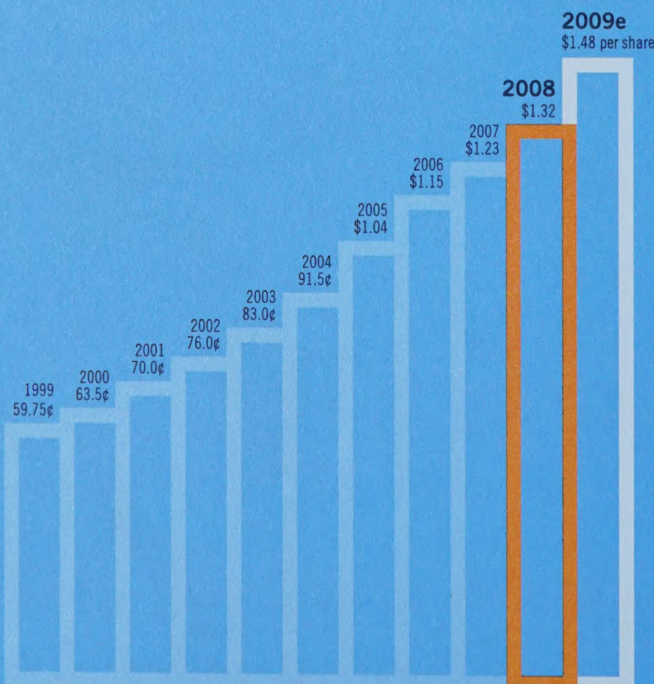
Strong dividends.

Currently, Enbridge aims to pay out 60% to 70% of adjusted earnings as dividends. In 2009, we have raised our quarterly dividend by 12%.

This represents the fourteenth consecutive year we've increased our dividend.

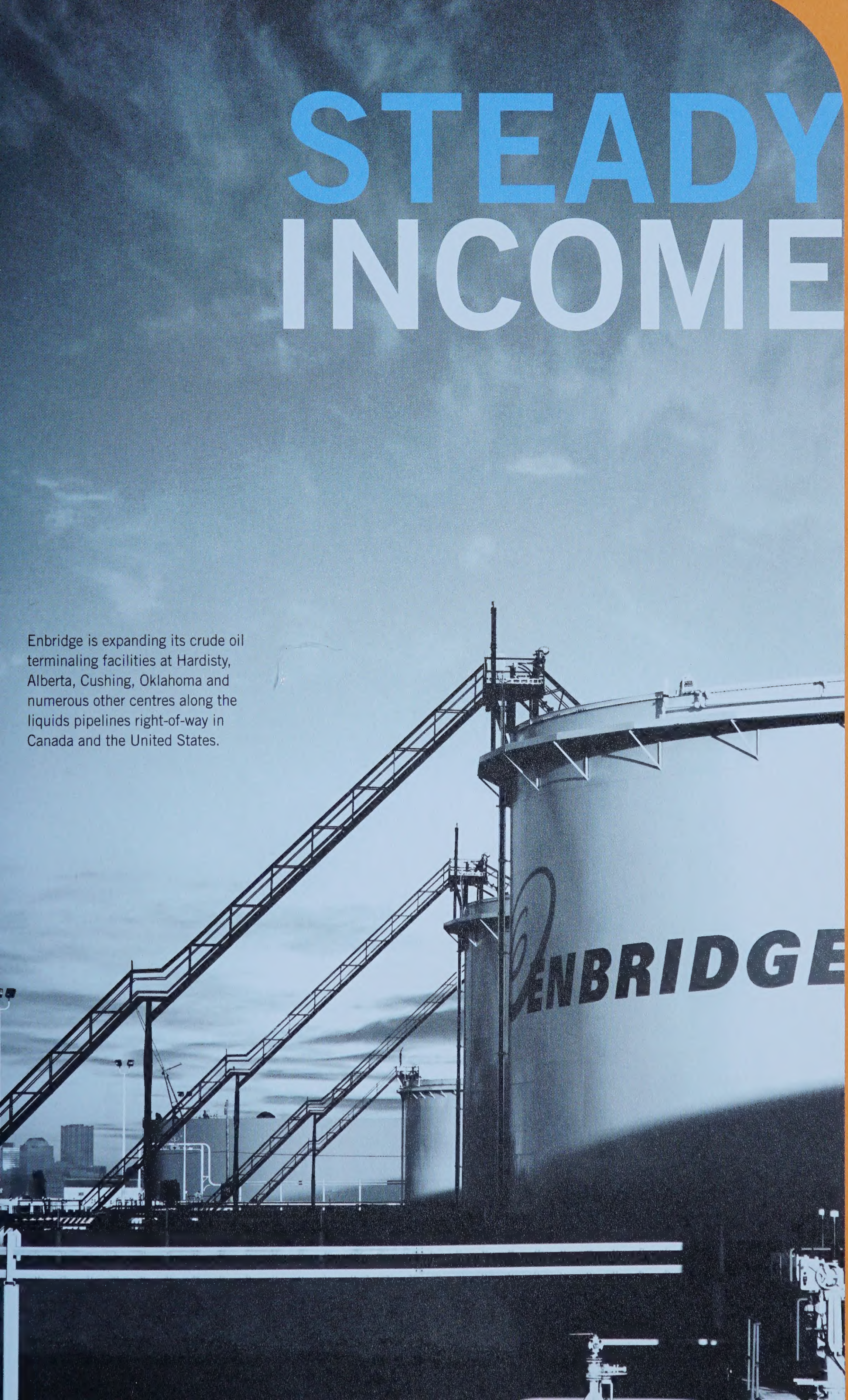
10-Year Dividend Trend

Over the last decade, Enbridge's dividend has grown on average by 9.5% annually.



STEADY INCOME

ENBRIDGE INC. 2008 ANNUAL REPORT



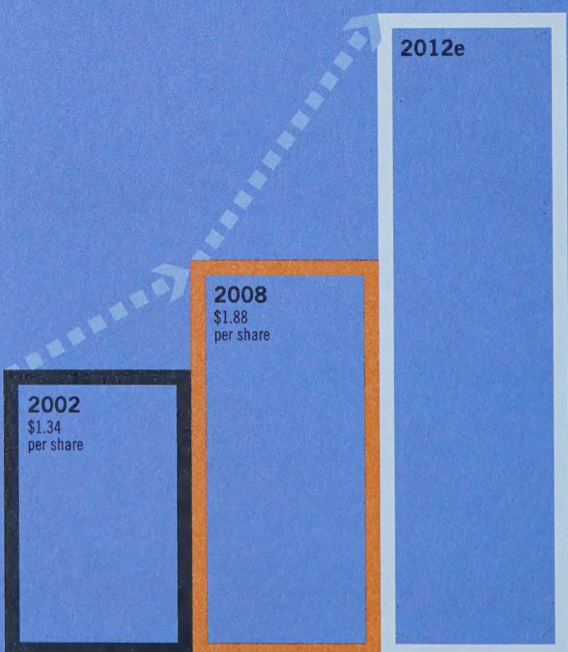
Enbridge is expanding its crude oil terminaling facilities at Hardisty, Alberta, Cushing, Oklahoma and numerous other centres along the liquids pipelines right-of-way in Canada and the United States.

We're growing.

Our current Liquids Pipelines growth projects will help us achieve average annual earnings per share growth of 10%+ over the next four years.

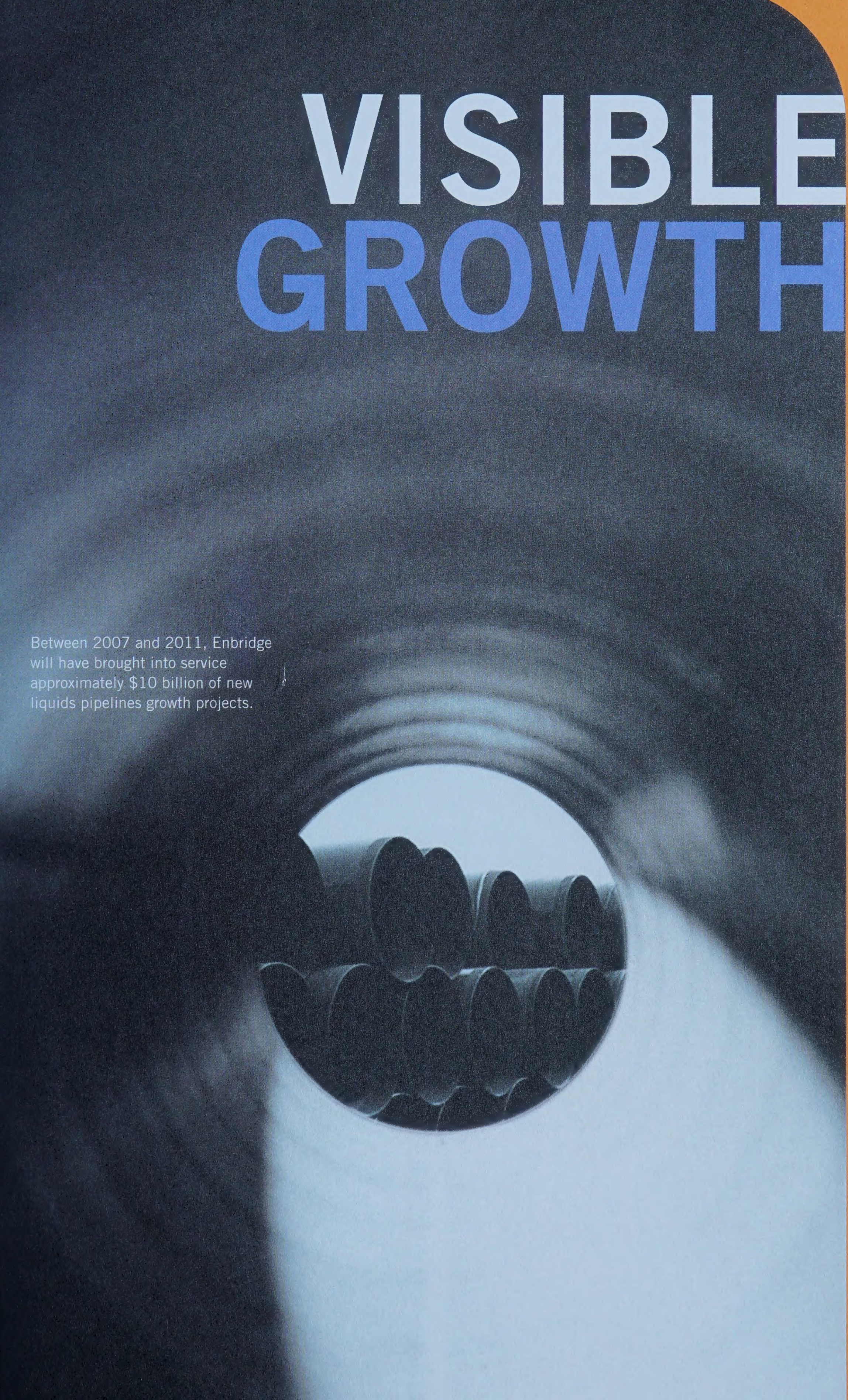
We're also well positioned to capture many opportunities in large and growing natural gas developments — onshore in both Canada and the U.S. and offshore in the Gulf of Mexico.

Earnings Per Share Growth



VISIBLE GROWTH

ENBRIDGE INC. 2008 ANNUAL REPORT



Between 2007 and 2011, Enbridge will have brought into service approximately $10 billion of new liquids pipelines growth projects.

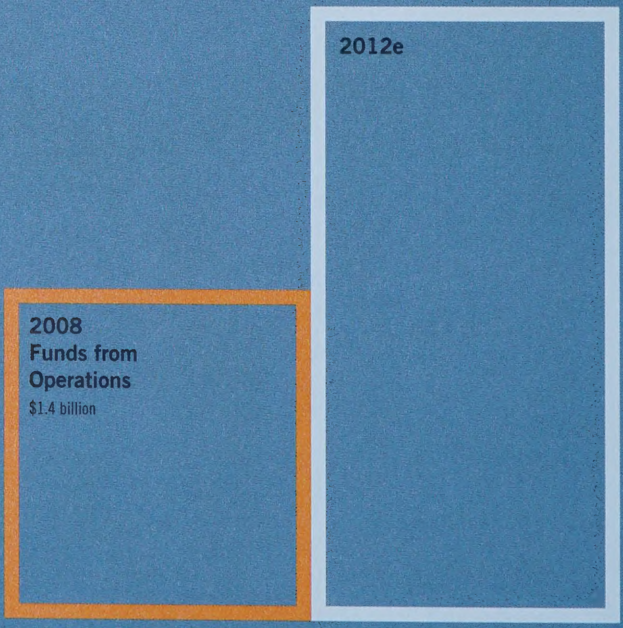
We are secure.

A strong balance sheet, solid cash flow, strong credit ratings and adequate credit facilities mean we can fund our current growth projects and take advantage of new opportunities.

With this financial flexibility, we can also choose the most advantageous time to consider debt or equity markets.

Growing Cash Flow

Funds from operations (FFO) will nearly double by 2012, providing a solid base for future growth.



WELL FINANCED

Ship Shoal 207 is a natural gas junction platform on Enbridge's Manta Ray System in the Gulf of Mexico.

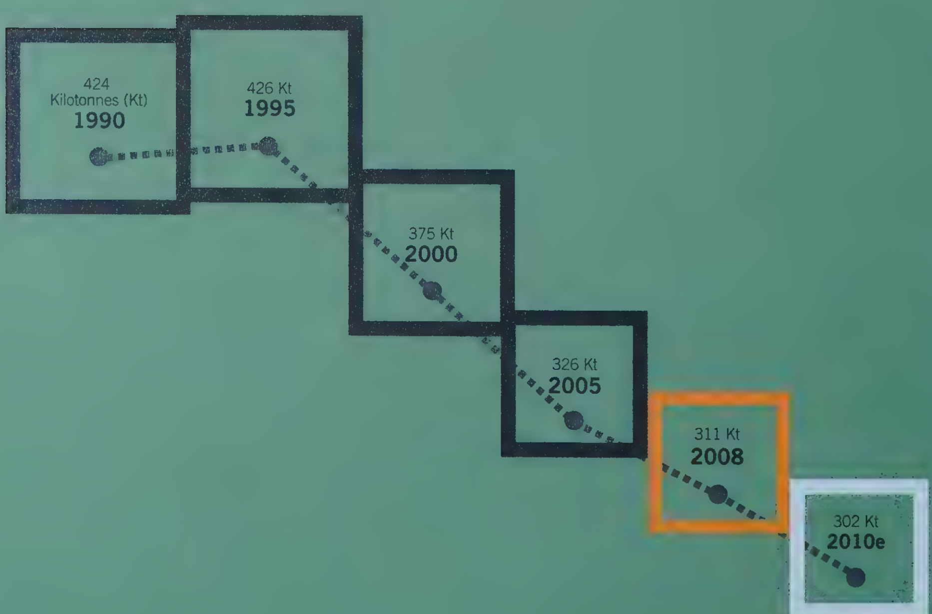
We have a responsibility for the future.

That's why we're investing in renewable and clean energy technologies including wind power, hybrid fuel cells and carbon dioxide sequestration.

We're also reducing our own greenhouse gas emissions and helping our customers reduce theirs.

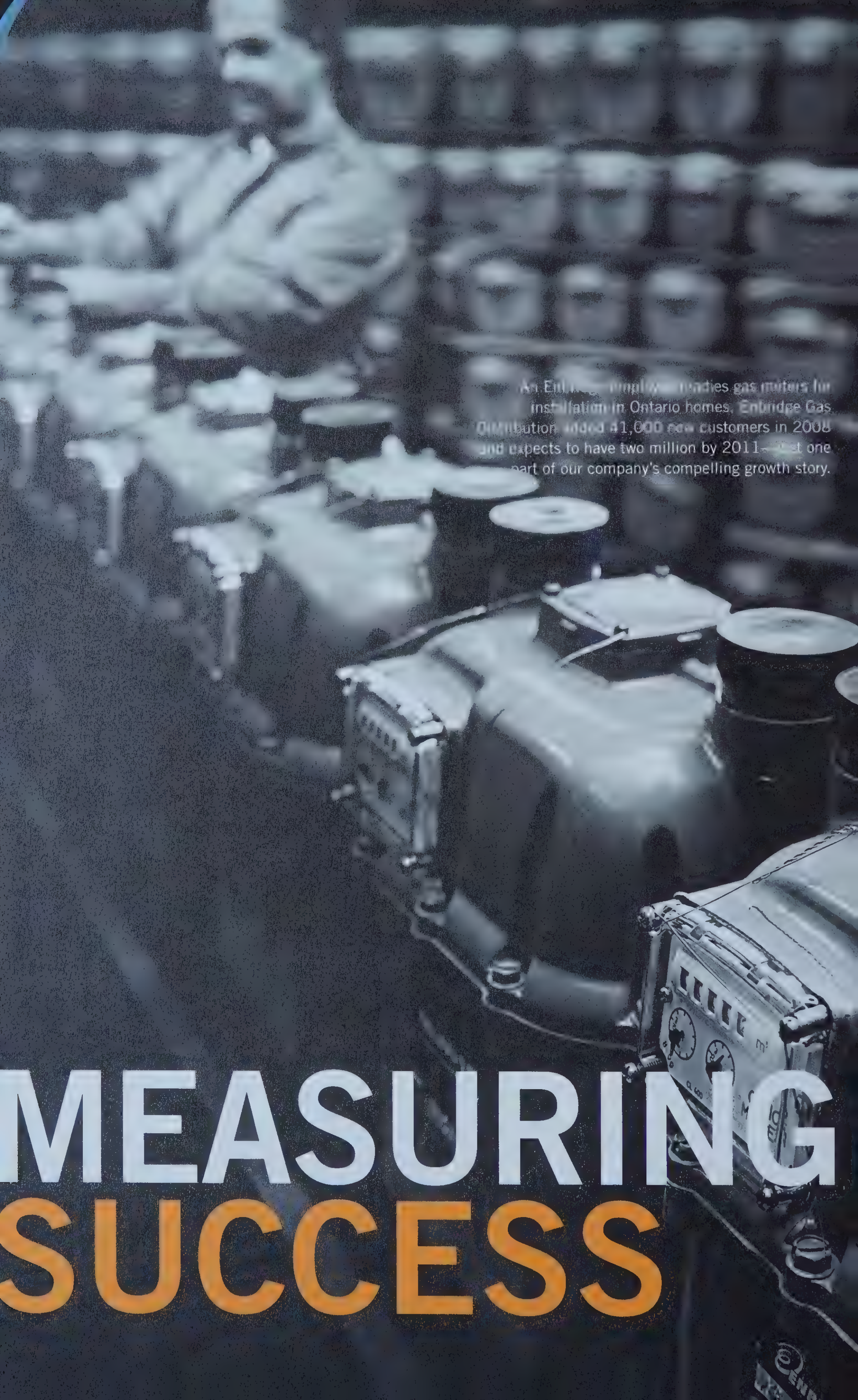
Reducing GHG Emissions

As of 2008, we had reduced our Canadian direct greenhouse gas (GHG) emissions by 27% below 1990 levels, exceeding our initial target of a 20% reduction by 2010. We're now revising our GHG reduction target for our Canadian operations and developing a Company-wide target that will include our assets in the U.S.



THINKING AHEAD

ENBRIDGE INC. ANNUAL REPORT



An Enbridge employee readies gas meters for installation in Ontario homes. Enbridge Gas Distribution added 41,000 new customers in 2008 and expects to have two million by 2011—just one part of our company's compelling growth story.

MEASURING SUCCESS

2008 HIGHLIGHTS

Year ended December 31,	2008	2007	2006
Financial *(unaudited; millions of Canadian dollars, except per share amounts)*			
Earnings Applicable to Common Shareholders	**1,320.8**	700.2	615.4
Earnings per Common Share	**3.67**	1.97	1.81
Adjusted Earnings per Common Share	**1.88**	1.79	1.74
Dividends per Common Share	**1.32**	1.23	1.15
Total Common Share Dividends Declared	**489.3**	452.3	403.1
Return on Average Shareholders' Equity	**22.2%**	13.6%	13.9%
Debt to Debt Plus Shareholders' Equity	**66.6%**	66.5%	68.6%
Operating			
Liquids Pipelines—Average Deliveries *(thousands of barrels per day)*			
Enbridge System [1]	**2,030**	2,005	2,013
Athabasca System [2]	**202**	164	190
Spearhead Pipeline	**110**	103	82
Olympic Pipeline	**291**	284	289
Gas Pipelines—Average Throughput Volume *(millions of cubic feet per day)*			
Alliance Pipeline US	**1,609**	1,598	1,592
Vector Pipeline	**1,321**	1,034	1,015
Enbridge Offshore Pipelines	**1,672**	2,060	2,153
Gas Distribution and Services			
Volumes [3] *(billions of cubic feet)*	**444**	450	408
Number of active customers [3] *(thousands)*	**1,942**	1,902	1,852
Degree-day deficiency [4]			
Actual	**3,802**	3,659	3,355
Forecast based on normal weather	**3,543**	3,617	3,745

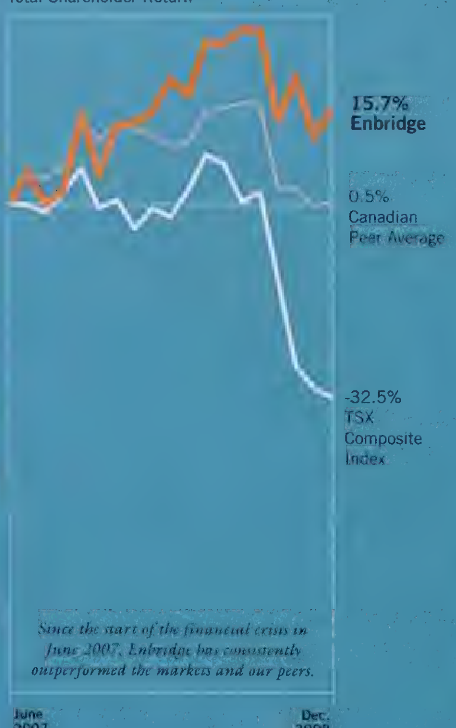
1 *Enbridge System includes Canadian mainline deliveries in Western Canada and to the Lakehead System at the U.S. border as well as Line 8 and Line 9 in Eastern Canada.*

2 *Volumes are for the Athabasca mainline and Waupisoo Pipeline and do not include laterals on the Athabasca System.*

3 *Gas Distribution and Services volumes and the number of active customers are derived from the aggregate system supply and direct purchase gas supply arrangements.*

4 *Degree-day deficiency is a measure of coldness, which is indicative of volumetric requirements of natural gas utilized for heating purposes. It is calculated by accumulating for each day in the period the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto Area.*

A SOLID YEAR



Since the start of the financial crisis in June 2007, Enbridge has consistently outperformed the markets and our peers.

LETTER TO SHAREHOLDERS

Dear Fellow Shareholders,

Our strong results in 2008 confirm that Enbridge's value proposition for investors of safety, income and growth can deliver even in a difficult economic environment.

Adjusted earnings per share increased approximately 6% to $1.88, which was near the midpoint of our guidance range. Actual earnings rose 89% to $1,321 million or $3.67 per common share, compared with $700.2 million or $1.97 per common share in 2007.

Our Total Shareholder Return (TSR) in 2008 was among the top ten on the TSX 60 index of Canada's largest companies. From the start of the credit crisis in mid-2007 to the end of 2008, a period of broad market decline, we significantly outperformed our peers in Canada and the United States, as well as the broader market indices.

DAVID A. ARLEDGE
Chair of the Board of Directors

PATRICK D. DANIEL
President and Chief Executive Officer

All of our businesses performed strongly in 2008. Enbridge is fortunate to have managed well through the crisis in the financial markets and slump in energy prices due to our strong business model. We also expect strong earnings in 2009, and on that basis Enbridge's Board of Directors has increased the 2009 annual dividend by 12%.

Our medium-term financial prospects are equally robust. We expect to grow annual earnings per share by more than 10% throughout our current planning horizon as we continue to bring our commercially secured crude oil pipeline projects into service. We remain confident of delivering 20% growth in 2009 alone.

Every aspect of our business today is strategically well positioned for growth.

Throughout 2008 we remained on schedule and on budget with the construction of our $12 billion of crude oil pipeline projects to serve growth in oil volumes.

We completed construction, and put into service the 350,000 barrels-per-day Waupisoo Pipeline, which links oil sands producers to their upgraders and refineries in Edmonton. The project was completed one month ahead of schedule and on budget, in an environment of tight labour markets and escalating costs.

And we have "shovels in the ground" on our remaining commercially secured projects that are scheduled to come into service over the course of 2009 and 2010, including mainline expansion projects Alberta Clipper, Line 4 and Southern Access Expansion; and, the Southern Lights diluent pipeline and the Hardisty Terminal Project.

These projects carry little or no volume risk nor commodity price risk which means returns are predictable.

We also made progress in 2008 on proposals to deliver a new stable and reliable source of Canadian crude oil to U.S. Gulf Coast markets. We entered into an agreement with BP Pipelines (North America) Inc. to develop a new delivery system between Illinois and Texas. We also continued to work with Exxon Mobil Corporation to develop the proposed Texas Access Pipeline.

While we now anticipate delays in a number of the heavy oil projects that drive our long-term development, we fully expect that all of the projects ultimately will proceed once crude oil prices recover and capital costs decrease.

OPPORTUNITIES ABOUND
FOR WELL-FINANCED
AND GEOGRAPHICALLY
WELL-POSITIONED
COMPANIES LIKE ENBRIDGE

As part of the cost structure for our customers, we are very much aware of the need to carefully manage the cost of our services across all aspects of our energy delivery business. We have a long track record of successfully managing costs, improving productivity and sharing the savings with our customers, and this has become an even more important success factor for Enbridge right now.

Opportunities abound for well-financed and geographically well-positioned companies like Enbridge.

We expect to see significant new natural gas infrastructure developments over the next five to 10 years in North America. Some of this growth will be driven by the increasingly important shale gas plays in British Columbia, Saskatchewan, North Dakota, Texas and Louisiana, as well as growing production from the U.S. Rockies and anticipated development in the deep-water in the Gulf of Mexico. Enbridge is strongly positioned to consider any and all opportunities that meet our criteria for safety, income and growth. We have the financial strength to be a valued partner in many of these developments.

Our existing gas assets all stand to benefit from these opportunities—the Alliance and Vector pipelines that move Western Canadian natural gas to the U.S. Midwest and Ontario; our substantial natural gas gathering, processing and transmission infrastructure in the Gulf of Mexico; and Enbridge Energy Partners, in which we increased our ownership stake to approximately 27% from approximately 15% in 2008.

Enbridge Gas Distribution (EGD) celebrated its 160th anniversary in 2008 with another year of improved results on the strength of continuing growth in residential and commercial customers as well as the new incentive regulation program. EGD is Canada's largest natural gas distribution utility, with approximately 1.9 million customers.

Internationally in 2008, our investment in Colombia again performed well, and we sold our 25% stake in CLH in Spain for $1.38 billion. We applied proceeds from the CLH sale toward funding our North American pipeline expansion projects.

Enbridge is one of the world's most sustainable corporations, and one of the ways we achieve

this is through our investment in renewable and clean energy initiatives:

- In 2008, we completed construction of a 190 megawatt Ontario wind project, the second largest wind farm in Canada.
- We are leading the Alberta Saline Aquifer Project (ASAP), which now includes 38 partners working to develop the long-term sequestration of CO_2. ASAP is the largest project of its kind in North America. We expect to begin construction on the pilot project this year, with injections of carbon dioxide beginning in 2010. We are participating in a similar initiative in Saskatchewan.
- We officially launched the world's first hybrid fuel cell, which produces 2.2 megawatts of environmentally preferred, ultra-clean electricity, or enough power for approximately 1,700 residences. Enbridge has exclusive North American distribution rights for the hybrid fuel cell technology.

Ensuring the safety of our employees, contractors and the public is always a top priority for Enbridge. We are deeply saddened to report that one of our valued colleagues, Henri St. Pierre, died in 2008 in an electrical accident at our Kerrobert, Saskatchewan, station. We have intensified our efforts to live up to our commitment of protecting the health and safety of all individuals affected by our activities.

Robert W. Martin will be retiring from the Board of Directors effective May 2009. A Board member since 1992, Bob was President and Chief Executive Officer of The Consumers' Gas Company Ltd. (now Enbridge Gas Distribution) from 1984 to 1992. The Board extends its warmest thanks to Bob for his years of dedicated service.

Enbridge is fundamentally in great shape. Our success in issuing $500 million of long-term debt in late 2008 in the midst of very uncertain capital markets is a testament to the Company's financial strength. We entered 2009 with approximately $3 billion of liquidity, which provides us with the flexibility we need to capitalize on our many growth opportunities.

Most notably, we are achieving these results at a time when both financial and commodity markets are facing unprecedented challenges. While we at Enbridge are proud of our results and our continuing ability to deliver value to our shareholders, we are mindful and respectful of the impact of current economic conditions on our customers, our business partners and the communities in which we do business.

Our more than 6,000 employees are committed to the task of safely delivering energy, and we wish to thank them for their outstanding achievements in 2008.

Over its 60-year history, Enbridge has been a very good investment for shareholders, consistently providing safety, income and growth. The best is yet to come over the next four years as shareholders reap the benefits of strong growth, increasing dividends and a safe haven during uncertain times.

David A. Arledge
Chair of the Board of Directors

Patrick D. Daniel
President and Chief Executive Officer

March 4, 2009

ENBRIDGE'S LEADERSHIP TEAM

We have structured our executive management team to ensure the successful execution of the Company's growth plans and to maintain the success of its current operations. Our goal is to continue to deliver superior returns to our shareholders and maintain the credibility the Company has earned with all of its stakeholders.

EXECUTIVE MANAGEMENT TEAM *(left to right)*

AL MONACO
Executive Vice President, Major Projects

PATRICK D. DANIEL
President & Chief Executive Officer

J. RICHARD BIRD
Executive Vice President, Chief Financial Officer & Corporate Development

DAVID T. ROBOTTOM
Group Vice President, Corporate Law

BONNIE D. DUPONT
Group Vice President, Corporate Resources

STEPHEN J.J. LETWIN
Executive Vice President,
Gas Transportation & International

STEPHEN J. WUORI
Executive Vice President, Liquids Pipelines

CORPORATE GOVERNANCE

At Enbridge, corporate governance means that a comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees of the Company.

Enbridge is committed to the principles of good governance, and the Company employs a variety of policies, programs and practices to manage corporate governance and ensure compliance.

The Board of Directors is responsible for the overall stewardship of Enbridge and, in discharging that responsibility, reviews, approves and provides guidance in respect of the strategic plan of the Company and monitors implementation.

The Board approves all significant decisions that affect the Company and reviews the results. The Board also oversees identification of the Company's principal risks on an annual basis, monitors risk management programs, reviews succession planning and seeks assurance that internal control systems and management information systems are in place and operating effectively.

BOARD OF DIRECTORS *(left to right)*

GEORGE K. PETTY Corporate Director
San Luis Obispo, California

CATHERINE L. WILLIAMS Corporate Director
Calgary, Alberta

E. SUSAN EVANS Corporate Director*
Calgary, Alberta

DAVID A. LESLIE Corporate Director
Toronto, Ontario

DAN C. TUTCHER Corporate Director
Houston, Texas

PATRICK D. DANIEL
President & Chief Executive Officer, Enbridge Inc.
Calgary, Alberta

DAVID A. ARLEDGE Chair of the Board, Enbridge Inc.
Naples, Florida

ROBERT W. MARTIN Corporate Director
Toronto, Ontario

J. LORNE BRAITHWAITE Corporate Director
Thornhill, Ontario

JAMES J. BLANCHARD Senior Partner,
DLA Piper U.S., LLP
Beverly Hills, Michigan

J. HERB ENGLAND Chairman & CEO,
Stahlman-England Irrigation Inc.
Naples, Florida

CHARLES E. SHULTZ Chair & Chief Executive Officer,
Dauntless Energy Inc.
Calgary, Alberta

Additional information about Enbridge's Corporate Governance, Board of Directors and Senior Management team can be found in the Corporate Governance section of Enbridge's website, at www.enbridge.com/investor/corporategovernance.

**Retired from the Board in May 2008.*

WELL POSITIONED

WE ARE IN AN UNPARALLELED POSITION BOTH FINANCIALLY AND GEOGRAPHICALLY TO EXPAND AND EXTEND OUR NETWORKS THROUGH ORGANIC AND OPPORTUNISTIC GROWTH.

OPERATIONS & ASSETS

Our first 60 years

In 2009, Enbridge is proud to celebrate the pioneering spirit of our forebears and our first 60 years of safely and reliably delivering energy. On April 30, 1949, Enbridge's predecessor, Interprovincial Pipe Line Company, received its charter and embarked upon the construction of the first crude oil pipeline connecting newly discovered oil fields in Alberta with eastern Canadian and U.S. markets.

LIQUIDS PIPELINES

WHAT WE'RE DOING TODAY

Enbridge is Canada's largest transporter of crude oil.

We export 69% of Western Canadian oil, which represents 11% of the U.S.'s daily crude oil imports. On any single day, Enbridge is the largest single conduit of oil into the U.S.

The Company's mainline is the world's longest, most sophisticated crude oil pipeline system. With an export capacity of 2.1 million barrels per day, we move close to 100 separate commodities, including more than 20 types of refined products.

HOW WE'RE BUILDING FOR TOMORROW

Enbridge is the preeminent pipeline provider to Canada's oil sands—the largest resource play in the world. With an estimated 178 billion barrels of oil sands reserves, Canada ranks second only to Saudi Arabia in global oil reserves.

Commercially Secured Growth

We are currently engaged in the largest capital program in our 60-year history—investing $12 billion to expand our North American pipeline and terminal network primarily to support broadening access of oil sands production to U.S. refining markets.

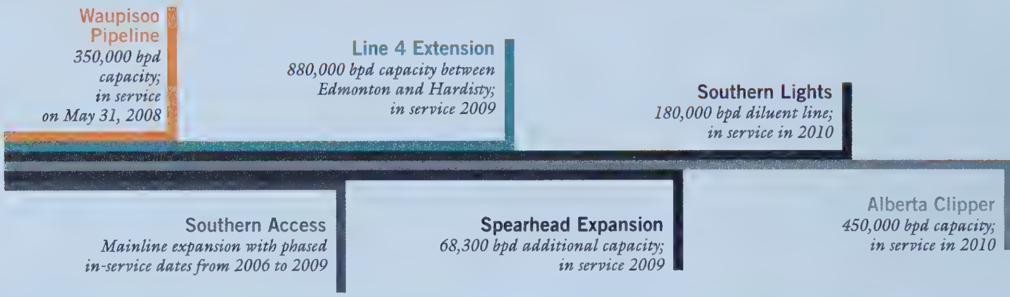
By 2011, we will have almost doubled the size of our Liquids Pipelines business, further diversifying the markets we serve and playing an even more significant role in energy delivery in North America.

Shovels in the Ground

Alberta Clipper construction began in August 2008 and is scheduled to be in service by mid-2010. Construction of Southern Lights began in late summer 2008 and is scheduled to be in service by the end of 2010.

The Alberta Clipper Expansion and Southern Lights projects will be built to the highest standards of pipeline safety and integrity using the latest pipeline engineering and construction technologies and practices.

COMMERCIALLY SECURED LIQUIDS PIPELINES PROJECTS



Bakken in Play

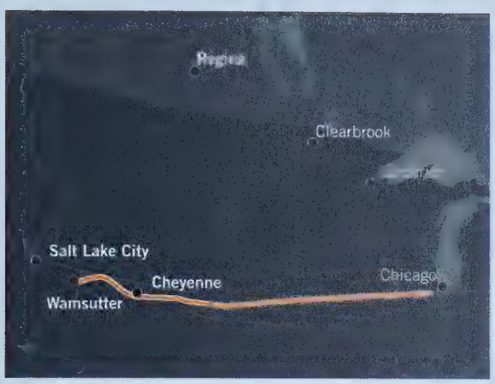
Our two sponsored investments—Enbridge Income Fund and Enbridge Energy Partners, L.P.—are expanding their pipeline systems to address significant growth in oil production in the Bakken Formation, which spans parts of Saskatchewan, North Dakota and Montana. The Energy Information Administration in the United States estimates that the Bakken shale has up to 503 billion barrels of resources in place (proven, probable and possible).

In response to increasing Bakken production in Saskatchewan, Enbridge Income Fund completed an expansion of its Westspur System in 2008, increasing capacity by 34% to 255,000 barrels per day (bpd). It also announced plans for a $100-million, 129,000-bpd expansion of its Weyburn, Westspur and Saskatchewan pipeline systems to be completed by 2010.

To serve North Dakota and Montana, Enbridge Energy Partners added 30,000 bpd of crude oil delivery capacity to its North Dakota System in 2007, bringing total capacity to 110,000 bpd, and is now proceeding with a further $150-million, 51,000-bpd expansion to be in service by early 2010.

Enbridge has a 72.3% overall economic interest in Enbridge Income Fund and a 27% overall ownership in Enbridge Energy Partners.

Alberta Clipper, which will provide Western Canadian producers additional transportation capacity to U.S. and Canadian markets, involves the construction of a new 914-millimetre (36-inch) diameter, 1,607-kilometre (1,000-mile) crude oil pipeline from Hardisty, Alberta, to Superior, Wisconsin.



NATURAL GAS GROWTH OPPORTUNITIES

Alliance Pipeline Inc. (50% owned by Enbridge) is jointly proposing a natural gas pipeline connecting the U.S. Rocky Mountain Region to the Chicago market hub. The proposed Rockies Alliance Pipeline — or RAP — is being developed in response to rapidly increasing supply from the U.S. Rockies region and will initially provide 1.3 billion cubic feet per day (Bcf/d) of transportation capacity, expandable to 1.7 Bcf/d. Pending commercial support, the pipeline is expected to be in service in 2013.

GAS PIPELINES

WHAT WE'RE DOING TODAY

Western Canada

Enbridge has major stakes in the Alliance and Vector natural gas pipeline systems. The Alliance System transports natural gas from the Western Canada Sedimentary Basin to the U.S. Midwest. Connecting with the Alliance System at Chicago, the Vector Pipeline provides natural gas supplies for local distribution and end-user customers in Illinois, Indiana, Michigan and Ontario.

Gulf of Mexico

Through Enbridge Offshore Pipelines, we today transport approximately 40% of all current deepwater natural gas production in the Gulf of Mexico, a prolific natural gas region. Enbridge Offshore Pipelines has interests in 11 transmission and gathering pipelines in five major pipeline corridors in Louisiana and Mississippi offshore waters.

Texas Gas

Enbridge Energy Partners is a large natural gas gatherer and processor in the Anadarko Basin, Barnett Shale and Bossier Sands of Texas, which are three of the top four areas for natural gas development in the U.S. Enbridge Energy Partners transports approximately 15% of Texas natural gas production. In 2008, Enbridge Inc. increased its ownership stake in Enbridge Energy Partners to 27% from approximately 15%.

HOW WE'RE BUILDING FOR TOMORROW

The **Alliance System** is well positioned for opportunities arising from the development of natural gas in northeast British Columbia, the U.S. Rocky Mountain region, Alaska and Canada's Arctic.

The **Vector Pipeline**, which expanded capacity in 2007 to 1.2 billion cubic feet per day (bcf/d), is undertaking a 0.1-bcf/d expansion in 2009 with potential further expansion in 2010 to 2011.

Enbridge Offshore Pipelines is growing its natural gas gathering, processing and transmission infrastructure in the Gulf of Mexico.

Enbridge Energy Partners expects to see strong growth in demand for processing and gathering pipelines to serve Texas onshore natural gas production.

160 YEARS OF EXPERIENCE

Enbridge Gas Distribution is building on a 160-year history of delivering energy to consumers safely and reliably. Our roots stretch back to 1848, when energy customers in Toronto incorporated a company then called Consumers Gas to secure a "purer, more regular, cheaper supply of gas." In marking our 160th anniversary in 2008, we honoured our past achievements and look forward to continuing leadership as one of North America's largest natural gas distributors.

Consumers Gas Building, Toronto, Ontario, ca. 1876

GAS DISTRIBUTION AND SERVICES

WHAT WE'RE DOING TODAY

Enbridge Gas Distribution is Canada's largest gas distribution utility and one of the fastest growing in North America. Enbridge Gas Distribution and its affiliates serve approximately 1.9 million customers in central and eastern Ontario, southwestern Quebec and parts of northern New York State. In 2008, Enbridge Gas Distribution added over 41,000 new customers and marked its 160th anniversary of operations.

In addition, Enbridge:

- owns 32.1% of Noverco Inc., which holds a majority interest in Gaz Métro Limited Partnership, the company that distributes natural gas in Quebec; and
- owns 70.9% of, and operates, Enbridge Gas New Brunswick (EGNB), which owns the natural gas distribution franchise in the province of New Brunswick.

HOW WE'RE BUILDING FOR TOMORROW

Enbridge Gas Distribution expects to add 35,000 customers in 2009 and have about two million customers by 2011.

We are optimizing the performance of Enbridge Gas Distribution through incentive regulation (IR), which went into effect in 2008. IR reduces regulatory costs. It also provides shareholder incentives for improved efficiency and revenue growth, more flexibility for utility management and shared cost savings with customers. The customer share of savings achieved in 2008 was \$5.8 million.

We are also positioning ourselves for opportunities such as new infrastructure for gas-fired power generation in Ontario and growth in Enbridge's unregulated businesses, including natural gas storage. In 2009, we are conducting an open season for approximately 2.5 bcf of new storage capacity.

Ottawa Expansion

The Alfred and Plantagenet project, one of the most significant system expansions undertaken in the Ottawa area in the last decade, will provide natural gas service to 2,800 new customers in three communities east of the city. Thanks to the innovation and teamwork of employees involved, this project met or exceeded all safety, quality, timing and budget targets. Organic growth projects are key in today's business environment, characterized by a declining new construction market.

ONTARIO WIND POWER

In 2008, Enbridge completed construction of its Ontario Wind Power project—the second largest wind farm in Canada. The 115-turbine wind farm located in Bruce County, Ontario, on the eastern shore of Lake Huron is contributing 190 megawatts of emissions-free energy to Ontario's grid—enough electricity to supply about 63,000 Ontario homes and reduce greenhouse gas emissions equivalent to taking about 30,000 vehicles off the road.

RENEWABLE AND GREEN ENERGY DEVELOPMENT

We are encouraging the use of renewable and clean energy by investing in wind power and new energy technologies such as fuel cells. We are also positioning ourselves for the future by participating in the emerging technology of carbon dioxide (CO_2) capture, pipelining and sequestration and participating in research for the safe transport of ethanol through pipelines.

WIND POWER

Enbridge owns a 100% working interest in the 190-megawatt Ontario Wind Power project. Located in Bruce County, Ontario, it is the second largest wind farm in Canada. Enbridge Income Fund owns interests in two wind farms in Alberta and one in Saskatchewan. These four wind power projects have a combined capacity of more than 260 megawatts, our share of which is enough green energy to provide 35% of our total Canadian crude oil mainline power consumption.

We expect future wind opportunities to come through expanding our existing operations, as well as developing new greenfield projects near Enbridge operations throughout North America, particularly where operating synergies can be applied.

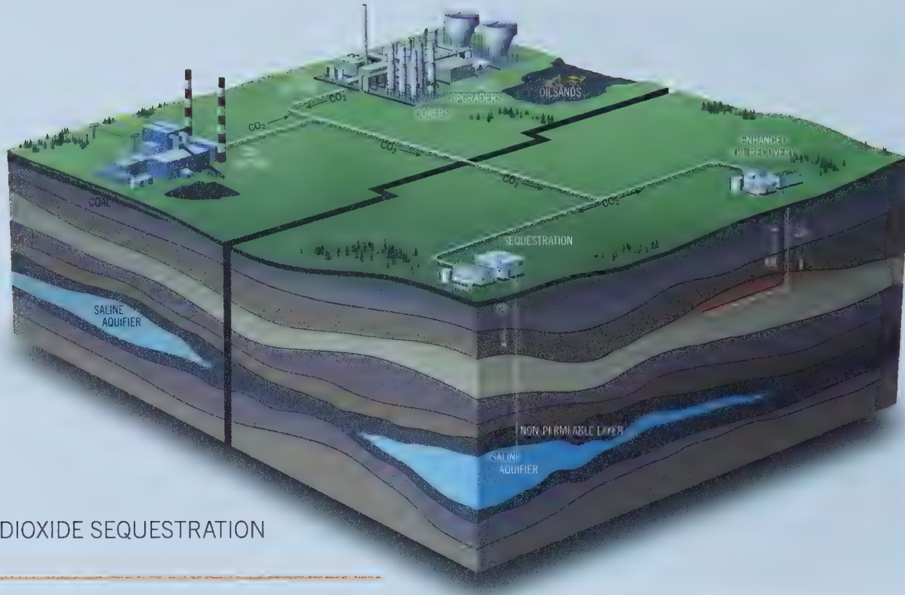
FUEL CELL POWER PLANT

In 2008, we officially launched the world's first hybrid fuel cell power plant that is designed for gas utility pressure reduction stations. The plant harvests pipeline energy that would otherwise be wasted, and the fuel cell operates without burning any fuel to produce about 2.2 megawatts of environmentally preferred, near zero-emissions electricity—enough to serve about 1,700 Ontario homes.

Enbridge has exclusive North American distribution rights for the hybrid fuel cell technology. We plan to replicate the plant throughout our distribution network in Ontario and market the hybrid fuel cell to other natural gas pipeline companies in North America.

SOLAR AND GEOTHERMAL

We are currently exploring the potential for solar power projects in Ontario and evaluating opportunities for taking an equity position in new solar power technologies. We are also examining our potential involvement in geothermal energy.



CARBON DIOXIDE SEQUESTRATION

CO_2 CAPTURE, PIPELINING AND SEQUESTRATION

Enbridge is involved in two initiatives in Canada that are investigating the feasibility of the long-term commercial sequestration of carbon dioxide (CO_2) in deep saline aquifers.

CO_2 capture, pipelining and sequestration developments are widely considered to be one of the most immediate, feasible and meaningful ways to reduce greenhouse gas emissions on a large scale and address the challenges posed by climate change.

We are leading a consortium of 38 energy industry participants in the Alberta Saline Aquifer Project (ASAP), and we are one of five participants in the Saskatchewan Aquistore project, which is managed by the Petroleum Technology Research Centre.

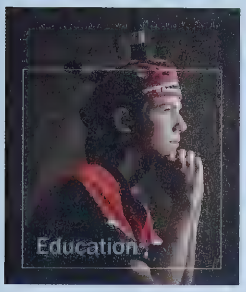
These initiatives will play a major role in advancing industry and government's knowledge of CO_2 capture and sequestration.

Phase I of ASAP, which is on track to be completed in spring 2009, has identified suitable deep saline aquifer locations for long-term CO_2 sequestration in Alberta. Saline aquifers are underground formations containing brine or salt water that is not suitable for agricultural purposes or for drinking.

The ASAP consortium also engaged in discussions with representatives of organizations that could supply large amounts of carbon dioxide. The goal is to sequester between 1,000 and 3,000 tonnes of CO_2 daily—the equivalent of pulling between 73,000 and 219,000 cars off Alberta roads.

Phase II of ASAP involves developing a pilot project, receiving all the necessary regulatory approvals and injecting carbon dioxide into the identified aquifers. The consortium now expects construction on the pilot project will begin in 2009 and injections of CO_2 to begin in 2010.

Phase III will involve expanding the pilot project to a large-scale, long-term commercial operation.



CORPORATE SOCIAL RESPONSIBILITY

ENBRIDGE'S DRIVE FOR OPERATING EXCELLENCE IS BUILT ON A STRONG FOUNDATION OF CORE VALUES AND CORPORATE SOCIAL RESPONSIBILITY POLICIES AND PRACTICES.

WE'RE BUILDING MORE THAN PIPELINES

As a leader in corporate social responsibility (CSR), we always aim to be the best by conducting business in a socially responsible and ethical way, protecting the environment and the health and safety of people, supporting human rights and engaging, respecting and supporting the communities and cultures in which we live and work.

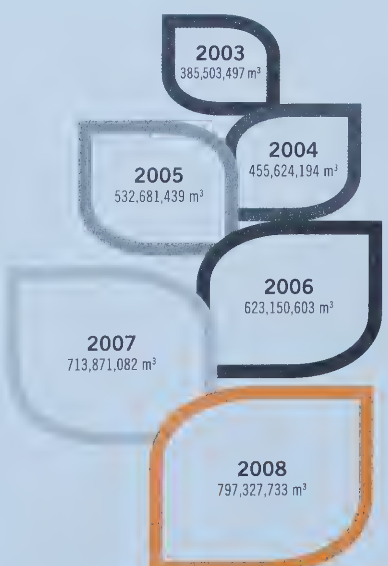
We want to make our communities more sustainable, so we're investing in four key building blocks—the environment, education, culture and community, and health and safety.

We believe we have a responsibility for the future and that our energy can make all the difference. For more information on the good thinking we're putting into improving our CSR performance, please visit our 2008 CSR Report at www.enbridge.com.

Improving Energy Efficiency

Enbridge Gas Distribution has more than 40 demand-side management (DSM) programs that encourage customers to adopt energy-saving initiatives to reduce consumption of natural gas. Since 1995, our DSM programs have delivered about 4.4 billion cubic metres of natural gas savings, the equivalent of enough gas to supply approximately 1.4 million homes for one year.

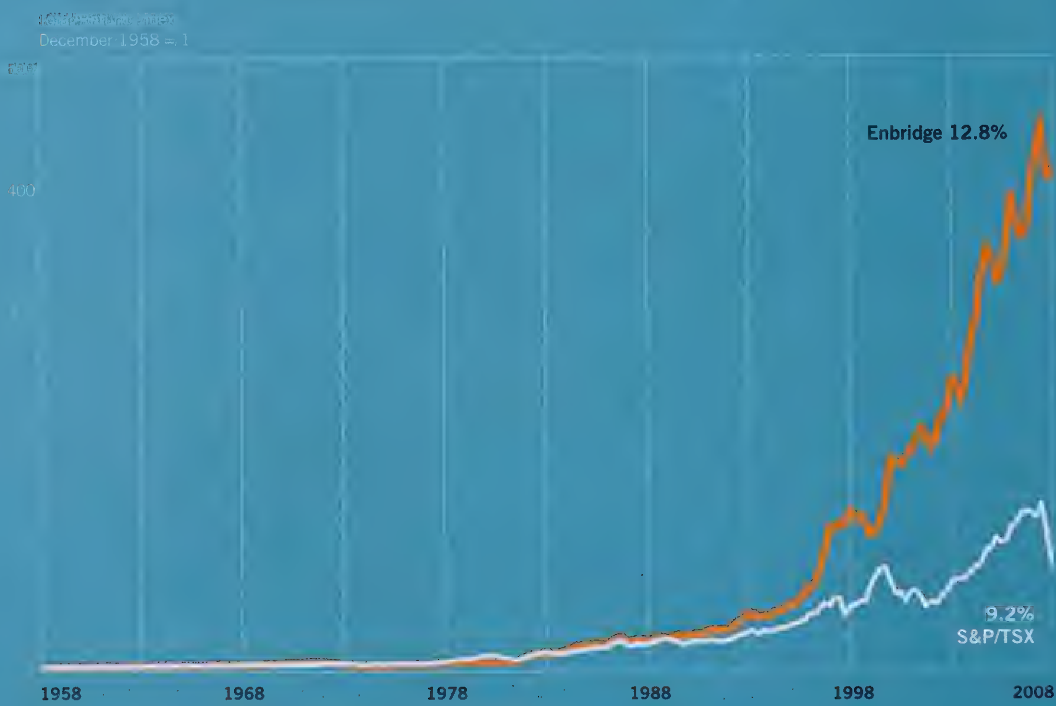
DSM Natural Gas Savings (by Volume)



FINANCIAL RESULTS

Total Shareholder Return

For over 50 years, we have achieved a 12.8% average annual return to shareholders and are focused on maintaining this enviable track record.



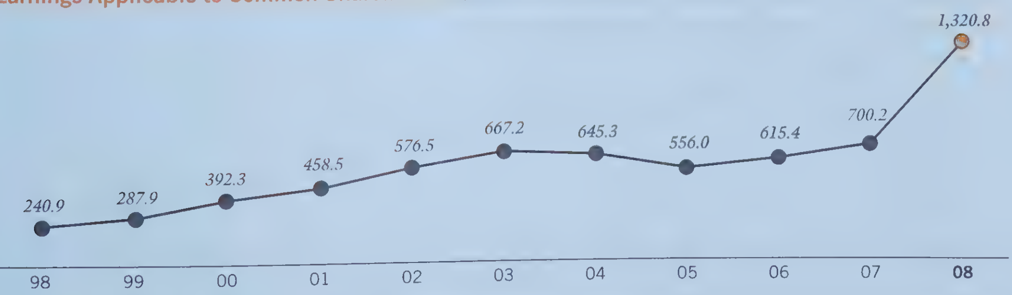
CONSOLIDATED EARNINGS

(millions of Canadian dollars, except per share amounts)	**2008**	2007	2006
Liquids Pipelines	**328.0**	287.2	274.2
Gas Pipelines	**48.5**	69.7	61.2
Sponsored Investments	**111.7**	96.9	86.8
Gas Distribution and Services	**300.6**	179.4	173.7
International	**608.2**	95.1	83.2
Corporate	**(76.2)**	(28.1)	(63.7)
Earnings Applicable to Common Shareholders	**1,320.8**	700.2	615.4
Earnings per Common Share	**3.67**	1.97	1.81
Diluted Earnings per Common Share	**3.64**	1.95	1.79

Earnings applicable to common shareholders were $1,320.8 million for the year ended December 31, 2008, or $3.67 per share, compared with $700.2 million, or $1.97 per share, for the same period in 2007. The increase in earnings resulted from allowance for equity funds used during construction (AEDC) in Liquids Pipelines, a higher contribution from Enbridge Gas Distribution (EGD) and unrealized fair value gains on derivative financial instruments in Aux Sable and Energy Services, partially offset by decreased earnings from International as the Company sold its interest in Compañía Logística de Hidrocarburos CLH, S.A. (CLH) in the second quarter of 2008. Earnings for the year ended December 31, 2008 also reflected a $556.1 million after-tax gain on the sale of CLH, partially offset by the recognition of a $32.2 million income tax charge as a result of an unfavourable court decision related to previously owned U.S. pipeline assets.

Earnings applicable to common shareholders were $700.2 million for the year ended December 31, 2007, or $1.97 per share, compared with $615.4 million, or $1.81 per share, in 2006. The $84.8 million increase was primarily due to colder than normal weather and strong performance at EGD, lower corporate interest expense and increased earnings at Enbridge Energy Partners, L.P. (EEP). The 2007 results also included a significant benefit from favorable legislated Canadian tax changes enacted in 2007. The positive factors were partially offset by lower contributions from the Aux Sable natural gas fractionation facility and Energy Services.

Earnings Applicable to Common Shareholders *(millions of Canadian dollars)*



FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this Management's Discussion and Analysis (MD&A) to provide Enbridge Inc. (Enbridge or the Company) shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Although Enbridge believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas and natural gas liquids; prices of crude oil, natural gas and natural gas liquids; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; anticipated in-service dates and weather.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, exchange rates, interest rates and commodity prices, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings, which represent earnings applicable to common shareholders adjusted for non-recurring or non-operating factors on both a consolidated and segmented basis. These factors are reconciled and discussed in the Financial Results sections for the affected business segments. Management believes that the presentation of adjusted earnings provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings to set targets, assess performance of the Company and set the Company's dividend payout target. Adjusted earnings and adjusted earnings for each of the segments are not measures that have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See Non-GAAP Reconciliation section for a reconciliation of the GAAP and non-GAAP measures.

ADJUSTED EARNINGS

(millions of Canadian dollars, except per share amounts)	2008	2007	2006
Liquids Pipelines	**332.1**	286.0	274.2
Gas Pipelines	**45.7**	64.4	61.2
Sponsored Investments	**100.9**	86.5	74.3
Gas Distribution and Services	**204.3**	168.9	177.7
International	**52.1**	89.9	83.2
Corporate	**(57.8)**	(59.2)	(77.7)
Adjusted earnings	**677.3**	636.5	592.9
Adjusted earnings per Common Share	**1.88**	1.79	1.74

Adjusted earnings were $677.3 million, or $1.88 per share, for the year ended December 31, 2008, compared with $636.5 million, or $1.79 per share, for the year ended December 31, 2007.

Significant operating factors that increased adjusted earnings in 2008 included:

- New facilities within Liquids Pipelines as well as AEDC on Southern Lights Pipeline and, within Enbridge System, on both Southern Access Mainline Expansion and Alberta Clipper Project.
- Increased Aux Sable adjusted earnings due to strong fractionation margins which enabled the Company to recognize earnings from the upside sharing mechanism.
- Higher incentive income and increased earnings at EEP primarily due to higher gas and crude oil delivery volumes, tariff surcharges for recent expansions and a greater ownership interest.
- Improved earnings in Energy Services resulting from market conditions which enabled higher margins to be captured on storage and transportation contracts as well as increased transportation and storage volumes.

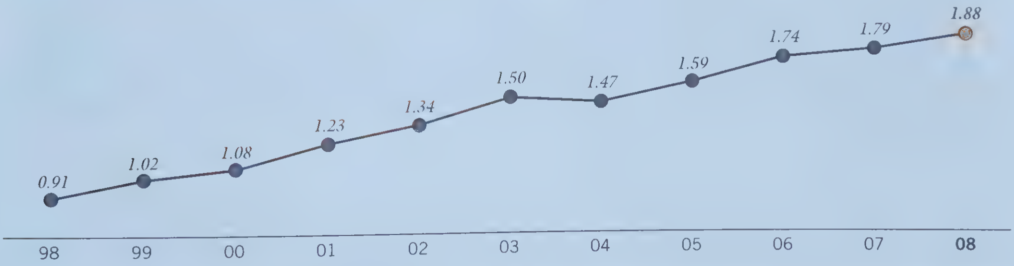
Significant operating factors that decreased adjusted earnings in 2008 included:

- Decreased earnings from International as a result of the sale of CLH in the second quarter of 2008.
- Lost revenue from Enbridge Offshore Pipelines (Offshore) as a result of Hurricanes Gustav and Ike.

2008 Commercial and Construction Accomplishments:

- Alberta Clipper, Southern Lights Pipeline and Line 4 Extension were approved by the National Energy Board (NEB) and construction began on the Canadian portion of Alberta Clipper Project, Line 4 Extension and various segments of Southern Lights Pipeline.
- First phase of the U.S. Southern Access Expansion Project has been completed on schedule and construction commenced on Phase 2 of Southern Access Expansion Project.
- Waupisoo Pipeline, which was completed one month ahead of schedule and on budget.
- Spearhead Pipeline expansion commenced.
- Project financing of US$1.3 billion and $0.4 billion secured for Southern Lights Pipeline.

Adjusted Earnings per Common Share *(Canadian dollars per share)*



CORPORATE STRATEGY

CORPORATE VISION AND KEY OBJECTIVE

Enbridge is an energy delivery company that transports natural gas and crude oil, which are used for many purposes, including to heat homes, power transportation systems and provide fuel and feedstock for industries. The Company's vision is to be North America's leading energy delivery company and its key objective is to generate superior shareholder value. The Company will deliver superior shareholder value through an investment proposition consisting of:

- industry leading earnings per share growth rate;
- a low risk commercial business model; and
- a balanced combination of near-term dividend income and capital appreciation.

STRATEGY

Enbridge's 2008 Strategic Plan consisted of four key strategic priorities to generate superior shareholder value and position the Company for the energy environment of the future.

1. **Expand Existing Core Businesses**
   Developing and operating energy delivery infrastructure assets remains the Company's core competency and strength. To capitalize on its asset position, Enbridge will pursue opportunities in both its liquids and natural gas delivery businesses. The Company will aggressively focus on the expansion and extension of its liquids pipeline and terminaling businesses. The Company will also seek to capture additional growth opportunities associated with its gas businesses to maintain as much diversification as is prudent. Strategies for each core business are included in the sections to follow.

2. **Focus on Operations**
   Effective day-to-day management of operations is integral to Enbridge's broader strategy. Achieving the Company's long-term objectives depends on its ability to consistently deliver safe, cost-effective and high quality service to customers and meet the broader expectations of communities it serves. Operational excellence will ensure that the Company is able to deliver consistent and predictable operating and financial performance while rapidly growing its asset and earnings base. Enbridge will continue its focus on operational excellence, including cost efficiency, safety and customer service.

3. **Mitigating and Managing Execution Risk**
   Executing Enbridge's unprecedented capital program demands effective strategies for mitigating and managing project development risk. Key priorities include enhanced project management systems and processes, proactive human resource planning and an increased focus on social investment, to both facilitate project development and meet the expectations of the Company's stakeholders.

4. **Developing New Platforms for Longer-term Growth**
   In the longer term, developing new business platforms will be important to maintaining growth and diversification within the Company. New platforms currently being pursued include renewable energy (wind and solar), CO2 transportation and sequestration and investment in smaller start-up entities to enable the development of new technologies that complement the Company's core operations.

To successfully pursue these strategies, the Company must also mitigate other risks. These risks, and the Company's strategies for managing them, are described under Risk Management.

Enbridge's strategy is reviewed annually with direction from its Board of Directors. The Company continually assesses ways to generate value for shareholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. Opportunities are screened, analyzed and must meet operating, strategic and financial benchmarks before being pursued.

COMPETITIVE ADVANTAGE

The Company's ability to execute its strategy and realize its corporate vision depends primarily on three key strengths. These include the strategic position of the Company's major assets, the diversification of its businesses and its consistent focus on operational excellence including customer service.

The Company's assets are well positioned in North America. In the Liquids Pipelines business, the Company operates a major conduit between U.S. markets and the attractive oil sands reserves in western Canada. Enbridge has economies of scale and scheduling flexibility because of its multiple separate lines and the flexibility to move over 95 different grades of crude oil. Enbridge's existing right of way is valuable in developing major expansion projects due to increasing environmental and landowner challenges in securing new or expanded energy corridors. Also, the Company serves a diversity of markets because of the extent and reach of its pipeline systems. The gas businesses are also well located. The Ontario gas utility franchise in Toronto benefits from significant customer addition rates due to immigration and urbanization.

The Company's sources of earnings and growth are diversified among liquids pipelines, gas pipelines, gas distribution and international investments. As well, the Company is actively exploring new growth platforms that would further diversify and complement existing core businesses.

The Company is focused on adding value for customers and improving customers' profitability. This focus has aligned the Company with supply-demand fundamentals, which have consistently formed a basis for the Company's strategy. The Company seeks to provide value to customers in a variety of innovative ways, including provision of access to new markets for producers and new sources of supply for refiners, diversifying the supply of diluent required for transportation of heavy crude and protection of batch quality and value.

GROWTH PROJECTS

The thrust of the Company's current strategy is growth through development and construction of new infrastructure. The Company is advancing the development of a number of organic growth projects, some of which are summarized below, which support annual organic earnings per share growth rates averaging 10% 'plus' over the 2007 to 2012 time frame. These projects are at various stages of development; some are recently completed and in service.

While different milestones are relevant to each, for simplicity management has classified projects into two categories – Commercially Secured and Under Development. Commercially Secured projects, including those being undertaken by EEP, are largely expected to be completed within the next two years. Projects Under Development are those which the Company believes it has a reasonable probability of competitively winning but has not yet completed commercial terms for. While Enbridge will undertake acquisitions that are accretive to earnings on an opportunistic basis, growth project execution remains the Company's primary near term focus. The following table summarizes commercially secured projects that have not yet been placed into service.

Commercially Secured Projects [1]	Estimated Capital Cost [2]	Expenditures to Date	Expected In-Service Date	Status
(in billions of Canadian dollars unless stated otherwise)				
Liquids Pipelines				
1. Southern Access Mainline Expansion – Canadian portion	$0.2 billion	$0.2 billion	2008	Substantially complete
2. Line 4 Extension	$0.3 billion	$0.2 billion	Early 2009	Under construction
3. Spearhead Pipeline Expansion	US$0.1 billion	US$0.1 billion	First half of 2009	Under construction
4. Hardisty Terminal	$0.6 billion	$0.4 billion	2009 (in stages)	Under construction
5. Southern Lights Pipeline	$0.5 billion + US$1.7 billion	$0.3 billion + US$0.9 billion	Light Sour Line – Early 2009; Diluent Line – Late 2010	Under construction
6. Alberta Clipper – Canadian portion	$2.4 billion	$0.8 billion	Mid-2010	Under construction
7. Fort Hills Pipeline System	~$2.0 billion	$0.1 billion	No earlier than 2012	Being reevaluated
Sponsored Investments				
8. EEP – Southern Access Mainline Expansion – U.S. portion	US$2.1 billion	US$1.9 billion	2008 - 2009 (in stages)	Under construction
9. EEP – North Dakota System Expansion	US$0.1 billion	No significant expenditures to date	Q1 2010	Under construction
10. EEP – Alberta Clipper – U.S. portion	US$1.2 billion	US$0.1 billion	Mid-2010	Awaiting regulatory approval
11. EIF – Saskatchewan System	$0.1 billion	No significant expenditures to date	Q3 2010	Pre-construction

1 Descriptions of each project are included in the strategy section for each business segment.

2 These amounts are estimates only and subject to upward or downward adjustment based on various factors.

Risks related to the development and completion of organic growth projects are described under Risk Management.


Fort McMurray
Edmonton
Hardisty
Chicago
Toledo
Patoka
Cushing
Houston
△ Liquids Pipelines
1 Southern Access Mainline Expansion—Canadian portion
2 Line 4 Extension
3 Spearhead Pipeline Expansion
4 Hardisty Terminal
5 Southern Lights Pipeline
6 Alberta Clipper—Canadian portion
7 Fort Hills Pipeline System
○ Sponsored Investments
8 EEP—Southern Access Mainline Expansion—U.S. portion
9 EEP—North Dakota System Expansion
10 EEP—Alberta Clipper—U.S. portion
11 EIF—Saskatchewan System
Current Assets
Growth Opportunities

DISRUPTION OF FUNCTIONING OF CAPITAL MARKETS

Multiple events during 2008 involving numerous financial institutions have restricted liquidity in the capital markets. Despite efforts by government agencies to provide liquidity to the financial sector, capital markets currently remain constrained. Given the Company's current and future growth and related funding requirements, these events and market conditions pose potential challenges. The Company's strong, predictable, internally generated cash flows; common share issuances under the Company Dividend Reinvestment and Share Purchase Plan; and access to adequate and recently increased committed credit facilities from diversified sources assist in mitigating these challenges. Maintaining the Company's investment grade credit rating may also support continued access to capital markets and debt refinancing at reasonable terms, if required. See Sensitivity Analysis and Risk Management – Credit Risk sections.

Decline in Commodity Prices

Since the end of the third quarter, commodity prices have significantly declined. As an energy transportation company, Enbridge has very limited direct exposure to commodity price changes and the Company employs comprehensive risk management practices to largely fix and mitigate any residual commercial exposures. Most significantly, the Company's assets and operations are largely secured by high quality shipper volume commitments. Similarly, liquids pipelines growth projects under construction are commercially secured with limited volume sensitivity and are therefore not expected to be significantly impacted by commodity price declines. Low commodity prices are resulting in the delays or cancellation of some oil and gas development and expansion projects. Should current trends continue long term, opportunities for future growth projects may be adversely affected. See Liquidity and Capital Resources.

DIVIDENDS

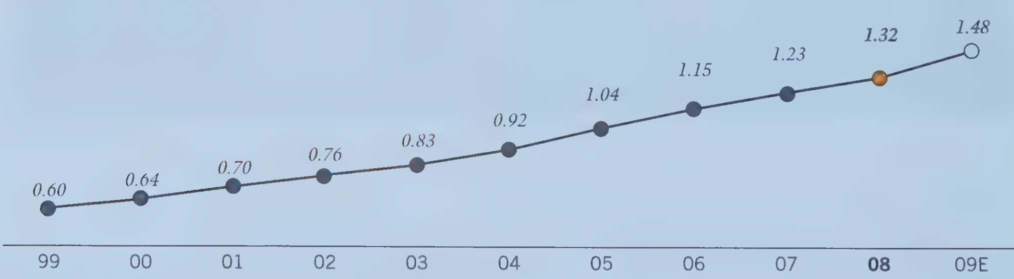
The Company has paid common share dividends since its inception. Based on estimated 2009 dividends, the rate of increase has averaged 10.1% since 1953. The Company's dividend payout ratio reflects a strong and stable long-term outlook for its business. Despite current economic conditions, in December 2008 the Company announced a 12% increase in its quarterly dividend to $0.37 per common share, or $1.48 annualized. The Company continues to target a pay out of approximately 60% to 70% of adjusted earnings as dividends and, with the most recent dividend increase, the 2009 pay out should be near the midpoint of the range. In 2008, dividends paid per share were 70% of adjusted earnings per share (2007 – 69%, 2006 – 66%).

The following chart shows dividends per share for the last 10 years, as well as estimated dividends for 2009, based on the quarterly dividend of $0.37 per common share declared by the Board of Directors on December 3, 2008.

CORPORATE SOCIAL RESPONSIBILITY

Enbridge has a strong foundation of core values and corporate social responsibility policies and practices. Enbridge defines Corporate Social Responsibility (CSR) as conducting business in a socially responsible and ethical way, protecting the environment and the health and safety of people, supporting human rights and engaging, respecting and supporting the communities and cultures with which the Company works.

Dividends per Common Share *(Canadian dollars per share)*



A comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees. Examples include compliance with applicable Sarbanes-Oxley requirements and the Canadian securities regulators' corporate governance guidelines and rules, the use of internal and external reviews and audits to assess each business segment's compliance with government regulations and internal policies and management systems, and to provide guidance for making further improvements. Employee and Director compliance with Enbridge's Statement on Business Conduct, a majority of independent Directors on the Company's Board of Directors and plain and open communication with stakeholders are other examples of stewardship and accountability.

Environmental initiatives include pursuing alternative and renewable energy technologies, minimizing pipeline leaks by conducting on-going inspection and maintenance programs and the development of a strategy to reduce greenhouse gas emissions. This strategy involves improving the energy efficiency of pipelines, encouraging the efficient use of natural gas by customers and replacing older cast iron pipe at EGD with new polyethylene mains. Enbridge engages employees on health and safety issues through training, communication programs and the establishment of local and regional Environmental, Health and Safety committees.

Stakeholder relations involves developing and maintaining positive relationships with employees, contractors, suppliers, customers, landowners, investors, community residents, aboriginal communities, business partners, government agencies and regulators, provincial, state and federal legislators, local officials, environmental groups and the media. Initiatives include early-stage project consultation with a variety of stakeholders on organic growth projects and public awareness programs on pipeline safety.

Enbridge supports universal human rights and reinforces this principle with comprehensive policies and practices addressing human rights. For example, Enbridge was one of the first Canadian companies to adopt the Voluntary Principles on Security and Human Rights, which stress the importance of promoting and protecting human rights throughout the world and the constructive role business can play in advancing these goals.

The Company makes voluntary contributions to charitable and non-profit organizations in the areas of: education, health, environment, social services, arts and culture, community leadership and volunteerism, in order to contribute to the economic and social development of communities where Enbridge employees live and work.

While Enbridge is focused on generating long-term value for investors, Corporate Social Responsibility defines the Company's commitment to achieving and sustaining that objective in a socially and environmentally responsible way.

CORE BUSINESSES

The Company's activities are carried out through five business segments:

- Liquids Pipelines, which includes the operation and construction of the Enbridge crude oil mainline system and feeder pipelines that transport crude oil and other liquid hydrocarbons.
- Gas Pipelines, which consists of the Company's interests in natural gas pipelines including Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines.
- Sponsored Investments, which includes investments in Enbridge Income Fund (EIF or the Fund) and EEP, both managed by Enbridge.
- Gas Distribution and Services, which consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario, the most significant being EGD. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, the Company's investment in Aux Sable, a natural gas fractionation and extraction business, and the Company's commodity marketing businesses.
- International, which includes the Company's energy-delivery investment outside of North America.

LIQUIDS PIPELINES

Liquids Pipelines consists of crude oil, natural gas liquids (NGLs) and refined products pipelines in Canada and the United States.

EARNINGS

(millions of Canadian dollars)	**2008**	2007	2006
Enbridge System	**211.5**	202.5	202.3
Athabasca System	**69.1**	53.7	52.8
Spearhead Pipeline	**12.0**	10.0	6.3
Olympic Pipeline	**7.1**	9.9	6.5
Southern Lights Pipeline	**27.6**	6.8	–
Feeder Pipelines and Other	**4.8**	3.1	6.3
Adjusted Earnings	**332.1**	286.0	274.2
Enbridge System – impact of tax changes	**–**	1.2	–
Feeder Pipelines and Other – asset impairment loss	**(4.1)**	–	–
Earnings	**328.0**	287.2	274.2

Liquids Pipelines adjusted earnings were $332.1 million in 2008 compared with $286.0 million in 2007. The increase was due primarily to strong contributions from the Enbridge and Athabasca Systems, as well as the recognition of AEDC on Enbridge System and Southern Lights Pipeline.

While under construction, certain regulated pipelines are entitled to recognize AEDC in earnings. These amounts will contribute to earnings throughout the Company's significant growth period and will be collected in tolls once the pipelines are in service. The earnings impact of AEDC for the year ended December 31, 2008 was $17.8 million (2007 – $2.9 million) for Enbridge System and $27.6 million (2007 – $6.8 million) for Southern Lights Pipeline.

Liquids Pipelines adjusted earnings were $286.0 million in 2007 compared with $274.2 million in 2006. The increase was due primarily to strong contributions from Spearhead and Olympic Pipelines, as well as the recognition of AEDC on Southern Lights Pipeline.

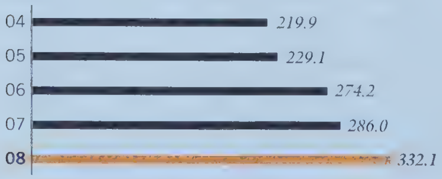
Liquids Pipelines earnings were impacted by the following non-operating adjusting items:

- In the fourth quarter of 2008, the Company recorded an impairment loss of $4.1 million on Manyberries Pipeline, a small feeder pipeline located in Canada.
- Enbridge System was affected by favorable tax rate changes in 2007.

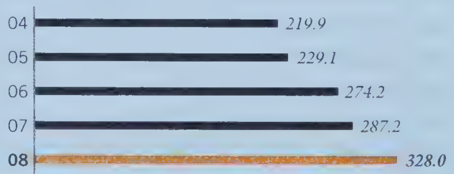
Liquids Pipelines revenues were $1,170.5 million in the year ended December 31, 2008, an increase of $79.6 million compared with $1,090.9 million in the year ended December 31, 2007. This increase is due to higher base tolls on Enbridge System and the new Waupisoo Pipeline included in the Athabasca System.

Revenues in the Liquids Pipelines segment increased to $1,090.9 million in the year ended December 31, 2007 from $1,048.1 million in the year ended December 31, 2006. The increased revenue was partially due to increased volumes on Spearhead Pipeline and higher tolls on Olympic Pipeline. In addition, revenue reflected full year contribution from Spearhead Pipeline and Olympic Pipeline.

Liquids Pipelines *Adjusted Earnings*
(millions of Canadian dollars)



Earnings
(millions of Canadian dollars)



ENBRIDGE SYSTEM

Liquids Pipelines

The mainline system is comprised of Enbridge System and Lakehead System (the portion of the mainline in the United States that is operated by Enbridge and owned by EEP). Enbridge has operated, and frequently expanded, the mainline system since 1949. Through five adjacent pipelines with a combined capacity of approximately 2.0 million barrels per day (bpd) the system transports various grades of crude oil and diluted bitumen from Western Canada to the Midwest region of the United States and Eastern Canada. Also included in Enbridge System and located in Eastern Canada are two crude oi pipelines and one refined products pipeline with a combined capacity of 0.4 million bpd. Average system utilization in 2008 was 85% and it is expected to increase in 2009.

Results of Operations

Enbridge System adjusted earnings were $211.5 million for the year ended December 31, 2008 compared with $202.5 million for the year ended December 31, 2007. Enbridge System adjusted earnings increased due to increased tolls from a higher rate base as a result of Southern Access Mainline Expansion entering service on March 31, 2008 and the AEDC recognized while the project was under construction.

Enbridge System adjusted earnings were $202.5 million for the year ended December 31, 2007 compared with $202.3 million for the year ended December 31, 2006. The effect of increased incentive tolling settlement (ITS) metrics bonuses and higher System Expansion Program (SEP) II utilization were offset by increased operating costs and higher taxes in the Terrace component, resulting in consistent earnings in 2007 and 2006.

For the years ended December 31, 2008 and 2006 adjusted earnings equaled earnings. In 2007, Enbridge System earnings increased by $1.2 million as a result of favorable tax rate changes.

Incentive Tolling

Tolls on Enbridge System are governed by various agreements, which are subject to the approval of the NEB. The NEB's jurisdiction over the Enbridge System includes statutory authority over matters such as construction, rates and ratemaking agreements and other contractual arrangements with customers. Significant agreements include the ITS applicable to the Enbridge mainline system (excluding Line 8 and Line 9), the Terrace agreement, the SEP II Risk Sharing Agreement and the Southern Access Expansion Agreement which is recovered via the Mainline Expansion Toll. Tolls on the core mainline system have been governed by incentive tolling settlements since 1995, with the current ITS term being effective through 2009.

The ITS allows the sharing of earnings in excess of a stipulated threshold and provides a fixed annual mainline integrity allowance. In addition, performance metrics bonuses and penalties were added to the current ITS to further align the Company's interests with its shippers. The Company has the opportunity to increase earnings by achieving performance targets and may incur penalties if performance falls short of specified thresholds.

Enbridge achieved total metrics bonuses of approximately $15 million for the year ended December 31, 2008 compared with approximately $11 million and $10 million for the years ended December 31, 2007 and 2006, respectively.

In conjunction with the Terrace Agreement, the ITS continues the throughput protection provisions included in earlier incentive tolling arrangements, ensuring the Company is insulated from volume fluctuations beyond its control. The agreements govern both current and future shippers on the pipeline and establish tolls each year based on an agreed capacity and an allowed revenue requirement. Where actual volumes on the pipeline fall short of the agreed capacity and Enbridge is unable to fully collect its annual revenue requirement, the deficiency is rolled into the subsequent year's tolls for collection from shippers at that time and a receivable, referred to as the Transportation Revenue Variance (TRV), is recognized. This basis may affect the timing of recognition of revenues compared with that otherwise expected under GAAP for companies that are not rate-regulated. As at December 31, 2008, $113.6 million (2007 – $143.4 million) was recorded as tolling deferrals.

Enbridge pays taxes each year only on the tolls collected in cash; therefore, the tax payable on the TRV lags behind the recognition of the revenue. As the Terrace capacity is increasingly utilized, there will be less TRV recorded and more cash tolls collected. This will result in the Company paying taxes in future years on both the prior year's TRV and the current year's cash tolls.

ATHABASCA SYSTEM

Athabasca System, includes two long haul pipelines, the Athabasca Pipeline and the Waupisoo Pipeline, as well as a variety of other facilities including the MacKay River, Christina Lake, Surmont and Long Lake facilities. It also includes the Company's interest in the Hardisty Caverns Limited Partnership, which provides crude oil tankage services, and two large terminals – the Athabasca Terminal located North of Fort McMurray, Alberta and the Cheecham Terminal which is a new hub located 95 kilometres south of Fort McMurray where the Waupisoo Pipeline initiates.

The Athabasca Pipeline is a 540-kilometre (335-mile) synthetic and heavy oil pipeline, built in 1999, that links the Athabasca oil sands in the Fort McMurray, Alberta region to a pipeline hub at Hardisty, Alberta. The Athabasca Pipeline has an ultimate design capacity of approximately 570,000 bpd and is currently configured to transport approximately 390,000 bpd.

The Company has a long-term (30-year) take-or-pay contract with the major shipper on the Athabasca Pipeline which commenced in 1999. Revenue is recorded based on the contract terms negotiated with the major shipper, rather than the cash tolls collected. The contract provides for volumes and tolls that will achieve an underpinning return on equity based on an assumed debt/equity ratio and level of operating costs. The committed volumes and the tolls specified in the contract do not generate sufficient cash revenues in the early years to compensate Enbridge for the debt and equity returns as well as the cost of providing service; therefore, Enbridge is recording a receivable in these years. This treatment ensures that the revenue recognized each period is in accordance with the contract. This receivable is contractually guaranteed by the shipper and will be collected in the later years of the contract.

The Waupisoo Pipeline is a 380-kilometre (236-mile) synthetic and heavy oil pipeline that entered into service on May 31, 2008 and provides access to the Edmonton market for oil sands producers. The Waupisoo Pipeline initiates at Enbridge's Cheecham Terminal and terminates at its Edmonton Mainline Terminal. The pipeline is currently configured to transport 350,000 bpd, but is ultimately rated for a design capacity of 600,000 bpd, providing Enbridge with opportunities for economic expansion achieved through the addition of pump stations to the line.

Enbridge has a long-term (25-year) take-or-pay commitment with the four founding shippers on the Waupisoo Pipeline who collectively have contracted for approximately one-third of the initial capacity on the line. The associated revenues provide for a base return on equity with significant upside potential as incremental founder and third party volumes are added.

Results of Operations

Earnings for the year ended December 31, 2008 were $69.1 million compared with $53.7 million for the year ended December 31, 2007. The increase in Athabasca System earnings reflected tolls collected on Waupisoo Pipeline since being placed into service at the end of May 2008 and the positive impact of terminal infrastructure additions. The increase in full year earnings was partially offset by higher operating costs.

Earnings for the year ended December 31, 2007 were $53.7 million compared with $52.8 million for the year ended December 31, 2006. The increase was due to earnings from infrastructure additions, partially offset by higher operating costs including increased property taxes and minor leak remediation costs.

SPEARHEAD PIPELINE

The Spearhead Pipeline commenced delivery of crude oil from Chicago, Illinois to Cushing, Oklahoma in March 2006. The performance of this 125,000 bpd pipeline has steadily increased and with the support of shippers, the Spearhead Pipeline Expansion is underway to increase capacity to 193,000 bpd.

Results of Operations

Earnings increased to $12.0 million for the year ended December 31, 2008 compared with $10.0 million for the year ended December 31, 2007 as a result of higher throughputs and higher tolls on committed volumes.

Earnings increased to $10.0 million for the year ended December 31, 2007 compared with $6.3 million for the year ended December 31, 2006. Spearhead Pipeline commenced operations at the beginning of March 2006; therefore, 2007 earnings reflect a full year of operations as well as increased throughput.

OLYMPIC PIPELINE

In February 2006, Enbridge acquired a 65% interest in the Olympic Pipeline from BP Pipelines (North America) Inc. (BP). Olympic is the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel and jet fuel. The pipeline system extends approximately 480 kilometres (300 miles) from Blaine, Washington to Portland, Oregon, connecting four Puget Sound refineries to terminals in Washington and Portland. BP is the operator of the pipeline.

Results of Operations

Earnings for the year ended December 31, 2008 were $7.1 million compared with $9.9 million for the year ended December 31, 2007. Olympic Pipeline earnings reflected lower average tolls effective July 1, 2008 to compensate for over collection in 2007. Olympic's cost of service tolling methodology requires annual toll adjustments for over or under collection of the cost of service in prior years. 2008 earnings also reflected an increase in pipeline integrity costs.

Earnings for the year ended December 31, 2007 were $9.9 million compared with $6.5 million for the year ended December 31, 2006. Higher tolls as well as a full year contribution from Olympic Pipeline resulted in the $3.4 million increase.

SOUTHERN LIGHTS PIPELINE

This pipeline received regulatory approval in Canada in the first quarter of 2008 and is currently under construction in both the United States and Canada. Upon completion, the 180,000 bpd, 20-inch diameter Southern Lights Pipeline will transport diluent from Chicago, Illinois to Edmonton, Alberta.

Results of Operations

The Company is entitled to collect an AEDC in tolls once the pipeline is in service. Earnings for both 2008 and 2007 reflect the AEDC recognized while the project is under construction.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other primarily includes the NW System, which transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta; interests in a number of liquids pipelines in the United States; contract tankage facilities; and business development costs related to Liquids Pipelines activities.

Results of Operations

Adjusted earnings in Feeder Pipelines and Other were $4.8 million for the year ended December 31, 2008 compared with $3.1 million for fiscal 2007. The increase in adjusted earnings resulted from a decrease in business development expenditures and improved operating results on a number of feeder systems.

Adjusted earnings for the year ended December 31, 2007 were $3.1 million compared with $6.3 million for fiscal 2006. The decrease in earnings was primarily due to increased business development costs related to the Company's organic growth projects.

Earnings for the year ended December 31, 2008 were impacted by an impairment loss of $4.1 million on Manyberries Pipeline.

STRATEGY

The Company seeks to go beyond the traditional regulated utility business model to create additional value for customers. In addition to incentive tolling models, the Liquids Pipelines strategy focuses proactively on understanding Western Canadian supply and downstream demand fundamentals and then proposing timely new or reconfigured infrastructure solutions to improve customer profitability.

Future Prospects for Liquids

Historically, Western Canada has been a key source of oil supply serving U.S. energy needs. For the past five years, Canada has surpassed both Mexico and Saudi Arabia to become the largest crude oil exporter to the U.S. Canada's oil sands, one of the largest oil reserves in the world, are becoming an increasingly prominent source of supply. Combined conventional and oil sands established reserves of approximately 178 billion barrels compare with Saudi Arabia's proved reserves of approximately 264 billion barrels. The NEB estimates that total Western Canadian Sedimentary Basin (WCSB) production averaged approximately 2.4 million bpd in 2008 and 2007. Development of the Alberta Oil Sands is expected to moderate due to declining demand and commodity prices and it is unlikely that all announced and planned oil sands projects will proceed as planned. The Canadian Association of Petroleum Producers' (CAPP) December 2008 estimates indicate that future production for the Alberta Oil Sands is expected to steadily increase to more than 1.8 million bpd by 2018 based on a subset of currently approved applications and announced expansions. The Company is actively working with customers to ensure that Enbridge mainline system will allow Canadian crude oil greater access to markets in the United States.

Crude oil price volatility in 2008 has caused some crude oil producers to cancel or defer projects that were planned to commence over the next decade. Cancellations and project deferrals are expected to temper the rate of growth over the next several years relative to prior forecasts. If the rate of crude oil production from the WCSB declines, immediate need for new pipeline infrastructure will likely decline. In addition to Enbridge's expansions, a significant competitor is expected to complete construction of a pipeline system to Wood River, Illinois. This competing pipeline, together with the Southern Access and Alberta Clipper expansions, may provide sufficient capacity for the near term. In this case, expansion activities will be more modest than experienced over the last several years. Although a number of oil sands projects have announced delays, the supply from the oil sands is forecasted to grow at a steady pace.

Key Components of the Liquids Pipelines Strategy

The Liquids Pipelines strategy is driven by shippers' need for adequate export capacity, market alternatives and economic sources of diluent, and U.S. refiners' need to maintain diversified sources of

supply. The five key components of the Liquids Pipelines strategy are discussed below as well as progress made to date and future plans towards further advancing the strategy.

1. Mainline Capacity Development

The Chicago refining market is expected to remain a major export destination for Western Canadian crude. The Company is working with shippers and refiners to further expand this market and markets beyond, both in Canada and the United States, through the Southern Access Mainline Expansion and the Alberta Clipper Project. The Line 4 Extension Project is a third, smaller debottlenecking project that has been undertaken to expand capacity.

Southern Access Mainline Expansion Project

The Southern Access Mainline Expansion Project will ultimately add a total of 400,000 bpd incremental capacity to the mainline system. In Canada, upgrades at 18 pump stations to improve pumping effectiveness are substantially complete. The Company started collecting associated tolls in April 2008.

In the United States, the new 42-inch diameter pipeline from Superior to Delavan, Wisconsin was placed into commercial service and was ready to receive linefill at the end of the first quarter of 2008. In the fourth quarter of 2008 the system began receiving crude, as it was made available by shippers, and is scheduled to be completely filled by the end of the first quarter of 2009. The first stage of the expansion adds capacity of approximately 190,000 bpd to the pipeline and system-wide toll surcharges were effective April 1, 2008 for the facilities that have been put into service. Construction of the second stage of the expansion project from Delavan, Wisconsin to Flanagan, Illinois, started in June 2008 and is on schedule for completion in the first quarter of 2009.

The expected cost of the project, which is fully recoverable in tolls, has decreased to an estimated US$2.3 billion (Enbridge – $0.2 billion, EEP – US$2.1 billion). The estimated capital cost for the Canadian portion was revised from $0.3 billion to $0.2 billion based on refinements to the scope of the project, agreed to with CAPP, to reflect the subsequent approval of the Alberta Clipper Project. Expenditures to date on the Southern Access Mainline Expansion are US$1.9 billion and $0.2 billion on the U.S. and Canadian portions, respectively.

Alberta Clipper Project

The Alberta Clipper Project involves the construction of a new 36-inch diameter pipeline from Hardisty, Alberta to Superior, Wisconsin generally within or alongside Enbridge's existing right-of-way. The Alberta Clipper Project will interconnect with the existing mainline system in Superior where it will provide access to Enbridge's full range of delivery points and storage options, including Chicago, Toledo, Sarnia, Patoka, Wood River and Cushing. The project will have an initial capacity of 450,000 bpd, is expandable to 800,000 bpd and will form part of the existing Enbridge System in Canada and the EEP Lakehead System in the United States.

In the first quarter of 2008, Enbridge received NEB approval to construct this 1,607-kilometre (1,000-mile) 36-inch diameter crude oil pipeline. Construction on the Canadian segment of the line commenced in August 2008, with an expected in-service date of mid-2010 and an expected cost of $2.4 billion, including escalation of the original "constant 2007 dollar" cost estimate to current "as spent" dollars, and allowance for funds used during construction (AFUDC). The U.S. segment, to be undertaken by EEP, is awaiting regulatory approval, with construction expected to begin in mid-2009. Subject to regulatory approval, the U.S. segment of the Alberta Clipper project is also expected to be in service in mid-2010. The cost of the U.S. segment is estimated at US$1.2 billion. Enbridge will share in cost overruns or savings against estimates, for costs deemed to be controllable costs. Controllable costs comprise approximately 70% of the total cost estimate.

Line 4 Extension Project

In April 2008 the NEB approved Enbridge's regulatory application for the construction and operation of the $0.3 billion Line 4 Extension project. Subsequent NEB route approval was received in July 2008. Construction commenced in August 2008, with the Line 4 Extension expected to be in service in early 2009.

2. Regional Oil Sands Development

Enbridge continues to be well positioned to capture significant growth from development of the regional infrastructure required to transport oil sands production to local markets or into major export pipelines. Successful execution of this strategy during 2007 and 2008 has further reinforced Enbridge's dominant position in the oil sands and provides increased leverage for future growth. Optimizing the Athabasca, Waupisoo and Fort Hills Pipelines will form the foundation of development efforts for the next wave of oil sands growth.

Fort Hills Pipeline System

In November 2007, Enbridge was selected by the Fort Hills Energy L.P. (FHELP) as their pipeline and terminaling services provider for both the initial phase of the Fort Hills project and all subsequent expansions. The scope of the Fort Hills Pipeline System is being re-evaluated by FHELP to reflect changing market conditions. The planned in-service date for the initial facilities has been deferred from mid-2011 to no earlier than 2012, subject to sanctioning of the overall project by FHELP.

3. Feeder System Expansions

Expanding the reach and capacity of the feeder pipeline systems will continue to be a priority. A particular focus will be the development of opportunities to expand gathering and feeder systems in Saskatchewan and North Dakota which are being driven by growing production from the Bakken play in the Williston Basin. The Company is advancing this component of its strategy through both the North Dakota System Expansion at EEP and the Saskatchewan System Capacity Expansion discussed in the Sponsored Investments section.

4. New Market Access

Enbridge's successful initiative to provide access for Canadian crude oil to the Cushing market through the acquisition and reversal of the Spearhead Pipeline has provided validation of the value to industry of market optionality. In addition to the planned construction of the Southern Access Extension which is expected to provide access to the Patoka market, Enbridge will continue to pursue new opportunities to provide broader market access for Canadian bitumen and synthetic crudes. Key opportunities being pursued include: Eastern PADD II access into the Michigan and Ohio markets; access to U.S. Gulf Coast refining centers through a combination of smaller incremental opportunities and large volume solutions; PADD I access into the East Coast market near Philadelphia; and the Northern Gateway pipeline to the Pacific Coast.

Enbridge System Deliveries *(thousands of barrels per day)*

Deliveries on the Enbridge System include Canadian mainline deliveries in Western Canada and to the Lakehead System at the U.S. border as well as Line 8 and Line 9 in Eastern Canada.

Southern Access Extension Project

The Southern Access Extension Project involves the construction of a new crude oil pipeline extending the mainline from Flanagan to Patoka, Illinois. Project timing is being re-evaluated given changing customer product export preferences and as a result of delays in the regulatory process and the May 2008 denial by the Federal Energy Regulatory Commission (FERC) of the Company's October 2007 filing seeking a declaratory order (i.e. advance approval) of the tariff rate structure for the pipeline. Enbridge remains committed to meeting the shippers' need for transportation of crude oil from the Chicago area to the Patoka, Illinois hub and is working with customers to reposition the project in a manner that is commercially appropriate for the market and includes a tolling structure acceptable to the FERC.

Spearhead Pipeline Expansion

Construction on the Spearhead Pipeline Expansion began in September 2008. This expansion, to be effected through additional pumping stations, will increase system capacity from Flanagan, Illinois to Cushing, Oklahoma by 68,300 bpd to 193,300 bpd. The expansion is expected to cost US $0.1 billion and to be completed in the first half of 2009.

U.S. Gulf Coast Access

Based on feedback from shippers, Enbridge's focus will be on smaller scale alternatives involving low cost reconfiguration of existing facilities to accommodate U.S. Gulf Coast market access at volumes which are more closely aligned with supply growth.

United States Gulf Coast Joint Initiative The Company and BP are currently developing an initiative to deliver incremental volumes of Canadian heavy crude oil to U.S. Gulf Coast markets. The initiative would involve the reversal of the BP #1 pipeline system between Flanagan, Illinois and Cushing, Oklahoma as well as the use of existing pipelines and rights-of-way between Cushing and Houston, Texas. The scope of the project provides for a pipeline system with over 150,000 bpd of new capacity between Flanagan and Cushing and approximately 250,000 bpd of capacity between Cushing and Houston. BP is expected to be a significant shipper on the new system. The partners are currently finalizing commercial terms to present to additional shippers who have indicated interest in this alternative. The target in-service date for the pipeline system is late 2012.

Trailbreaker Project The Company initiated plans to provide access for western Canadian crude oil to refineries along the U.S. eastern seaboard and the U.S. Gulf Coast via the marine terminal at Portland, Maine. The Trailbreaker project contemplates the expansion and reversal of existing facilities to create a pipeline route to Portland. An open season process held by third-party owned Portland-Montreal Pipe Line did not receive sufficient commercial support for the reversal of one of its pipelines to transport crude oil from Montreal, Quebec to Portland. As a result, CAPP has exercised its right to withdraw support from the project at this time. Enbridge continues to engage in discussions with customers to determine timing and conditions for proceeding with this project.

Texas Access Pipeline The Company will continue to work with Exxon Mobil to develop the 450,000 bpd Texas Access Pipeline to provide the lowest cost large scale transportation solution to meet shippers' post-2012 requirements to providing U.S. Gulf Coast access for the volumes and on the schedule required by shippers.

Northern Gateway Project

The Northern Gateway Project involves constructing a twin pipeline system running from near Edmonton, Alberta, to a new marine terminal in Kitimat, British Columbia. One pipeline will transport crude oil for export from the Edmonton area to Kitimat, and is expected to be a 36-inch diameter line with an initial capacity of 525,000 bpd. The other pipeline will be used to import condensate and is expected to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

The Company has secured funding from third party oil sands producers and Pacific Rim refiners to seek regulatory approval of the project.

The Company has requested the NEB and the Canadian Environmental Assessment Agency (CEAA) to resume their activities in respect of the environmental assessment process for the proposed project. CEAA will carry out consultations with potentially affected Aboriginal groups. The project is undergoing its own comprehensive public consultation program, which includes a series of community open houses designed to gather input, answer questions and build public awareness and understanding about the project.

The Company is committed to working with First Nations and Métis communities along the pipeline route to create opportunities for economic partnerships and to incorporate traditional knowledge into the planning and operations of the proposed project. See Aboriginal Relations.

Enbridge expects to file its regulatory application with the NEB in 2009. Subject to continued commercial support, regulatory and other approvals, the Company estimates that Northern Gateway could be in-service in the 2014 to 2015 time frame. The NEB posts public filings related to Northern Gateway on its website and Enbridge also maintains a Northern Gateway Project page on its own website. None of the information contained on, or connected to, either the NEB website or Enbridge's website is incorporated or otherwise part of this MD&A and we disclaim any intent to incorporate any of such information, either expressly or by reference.

5. Diluent Supply and Refined Products

With the Southern Lights diluent pipeline project on schedule for completion in 2010, the Company's strategy has shifted to expanding the number of physical connections to the pipeline to increase available supply in the U.S. and available market outlets in Alberta. Selective development of refined products infrastructure will also be pursued.

Southern Lights Pipeline

When completed, the 180,000 bpd Southern Lights pipeline will transport diluent from Chicago, Illinois to Edmonton, Alberta. The project involves reversing the flow of a portion of Enbridge's Line 13, an existing crude oil pipeline which runs from Edmonton to Clearbrook, Minnesota. In order to replace the light crude capacity that would be lost through the reversal of Line 13, the Southern Lights Project also includes the construction of a new 20-inch diameter light sour crude oil pipeline (LSr Pipeline) from Cromer, Manitoba to Clearbrook, and modifications to existing Line 2. These changes to the existing crude oil system will ultimately increase southbound light crude system capacity by approximately 45,000 bpd.

The Canadian portion of the Southern Lights Pipeline received NEB approval in the first quarter of 2008, enabling construction to commence on the LSr Pipeline and Line 2 modifications. Line 2 modifications, which allow Line 2 to operate at higher design rates, were nearing completion at the end of 2008. Due to a delay in NEB routing approvals, the planned in-service date for the LSr Pipeline has been delayed to early 2009.

In the U.S., construction of the LSr Pipeline and Line 2 modifications are complete. Diluent pipeline construction between Superior and Delavan, Wisconsin was completed in early 2008. Construction of the second segment of the diluent pipeline between Delavan, Wisconsin and Streator, Illinois was also substantially completed in 2008. Construction of the remaining U.S. line segments will commence in 2009. The diluent line is expected to be in service in late 2010.

The total expected project cost remains unchanged at US$1.7 billion (including AFUDC) for the U.S. segment and $0.5 billion (including AFUDC) for the Canadian segment.

6. Terminaling and Storage Infrastructure

In addition to regulated storage facilities, Enbridge owns and operates contracted storage adjacent to its pipeline systems. The Hardisty Terminal project will add an additional 7.5 million barrels of contract capacity. Liquids Pipelines continues to advance downstream terminaling projects at Flanagan, Patoka, Cushing and the U.S. Gulf Coast. Regulated storage initiatives will also be pursued at Edmonton, Superior, Griffith and Cromer.

Hardisty Terminal

Enbridge is building a crude oil terminal at Hardisty with a tankage capacity of 7.5 million barrels. Overall project construction was approximately 71% complete at the end of 2008. Tank capacities are expected to enter service in phases throughout 2009. Once complete, the $0.6 billion Hardisty Terminal will be one of the largest crude oil terminals in North America.

Stonefell Terminal – BA Energy

BA Energy Inc. proposed building a bitumen upgrader near Fort Saskatchewan, Alberta for which Enbridge had agreed to provide pipeline and terminaling services. In the second quarter of 2008, Enbridge was directed by BA Energy to stop work on this project and place the newly constructed tanks into standby. The Enbridge contractors have been demobilized and the project assets are in a storage mode. Project continuance and schedule are uncertain given BA Energy's filing for creditor protection. Enbridge's costs incurred to date, including a return on investment, have been fully reimbursed by BA Energy.

CAPITAL EXPENDITURES

In 2008, the Liquids Pipelines segment spent $164 million on capital maintenance and improvements compared with an expected $150 million. In 2009, the Company expects to spend approximately $160 million on capital maintenance and improvements.

Total expenditures for organic growth projects described above were $2.7 billion for 2008 compared with an expected $2.8 billion. For 2009, the Company expects to spend $2.9 billion for the organic growth projects. Discussion of the Company's access to financing is included under Liquidity and Capital Resources.

BUSINESS RISKS

The risks identified below are specific to the Liquids Pipelines business. General risks that affect the Company as a whole are described under Risk Management.

Supply and Demand

The operation of the Company's liquids pipelines depends on the supply of, and demand for, crude oil and other liquid hydrocarbons from Western Canada. Supply, in turn, depends on a number of variables, including the price of crude oil and bitumen, the availability and cost of capital and labour for oil sands projects and the price of natural gas used for steam production.

Demand depends, among other things, on weather, gasoline price and consumption, manufacturing, alternative energy sources and global supply disruptions.

Competition

Competition among pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. Other competing carriers are available to producers to ship western Canadian liquids hydrocarbons to markets in either Canada or the United States. Competition could also arise from pipeline proposals that may provide access to market areas currently served by the Company's liquids pipelines. One such competing project is currently under construction to initially serve markets at Wood River, Illinois and Cushing, Oklahoma, commencing in late 2009. This pipeline will have an initial capacity of 435,000 bpd and an ultimate capacity of 590,000 bpd. Commercial support has also been announced to construct additional ex-Alberta capacity of 500,000 bpd for an in-service date during 2012, which would be complemented by an extension of the system from Cushing, Oklahoma to Nederland, Texas. The Company believes that its liquids pipelines are serving larger markets and provide attractive options to producers in the WCSB due to their competitive tolls and multiple delivery and storage points.

Also, shippers are not required to enter into long-term shipping commitments on Enbridge's mainline system. The Company's existing right-of-way provides a competitive advantage as it can be difficult and costly to obtain new rights of way for new pipelines. The ITS and the Terrace Agreement on the

Enbridge System provide throughput protection which insulates the Company from negative volume fluctuations beyond its control. The Lakehead System, owned by EEP, has no similar throughput protection on its existing system but will on the Southern Access and Alberta Clipper expansions.

Increased competition could arise from new feeder systems servicing the same geographic regions as the Company's feeder pipelines.

Alberta Royalty Review

In September 2007, the Alberta Royalty Review Panel issued its recommendations to the government of the Province of Alberta calling for the adoption of measures to increase the Alberta government's share of revenues from oil sands development. A majority of the recommendations of the report were subsequently adopted by the Alberta government and became effective January 1, 2009. These measures may impact how oil sands developers evaluate future projects and this may reduce the level of future volumes expected to flow through the mainline system.

ITS Metrics

The ITS governing the Enbridge System measures the Company's performance in areas key to customer service. If the Company fails to meet the baseline targets set out in the ITS for all service and reliability metrics, the Company could be required to pay penalties to shippers up to a maximum of $30 million in 2009.

Potential Pressure Restrictions

The Company's Liquids Pipelines systems consist of individual pipelines of varying ages. With appropriate inspection and maintenance, the physical life of the pipeline is indefinitely long; however, as the pipelines age the level of expenditures required for inspection and maintenance may increase. Temporary pressure restrictions have been established on some sections of certain pipelines pending completion of specific inspection and repair programs. Pressure restrictions may from time to time be established on other of the Company's pipelines. Pressure restrictions reduce the available capacity of the applicable line segment and could result in a loss of throughput if and when the full capacity of that line segment would otherwise have been utilized. Pressure restrictions to date have not given rise to any loss of throughput. While the Enbridge System is volume-protected, EEP's Lakehead System and certain other pipelines would be adversely affected by pressure restrictions that reduce volumes transported. Additionally, on the Enbridge System ITS metrics penalties may apply if available capacity is reduced below baseline targets.

Regulation

The Enbridge System and other liquids pipelines are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings from those operations. The NEB prescribes a benchmark multi-pipeline rate of return on common equity, which is 8.57% in 2009 (2008 – 8.71%). To the extent the NEB rate of return fluctuates, a portion of the Enbridge System and other liquids pipelines earnings will change. The Company believes that regulatory risk is reduced through the negotiation of long-term agreements with shippers, such as the ITS, Terrace Agreement and agreements for projects currently under construction, which will govern the majority of the segment's assets.

GAS PIPELINES

Gas Pipelines activities consist of investments in Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines. Enbridge has joint control over these investments with one or more other owners. Enbridge owns a 50% interest in Alliance Pipeline US, a 60% interest in Vector Pipeline and interests ranging from 22% to 100% in the pipelines comprising Offshore.

EARNINGS

(millions of Canadian dollars)	2008	2007	2006
Alliance Pipeline US	**24.9**	27.7	29.7
Vector Pipeline	**14.2**	14.9	13.4
Enbridge Offshore Pipelines	**6.6**	21.8	18.1
Adjusted Earnings	**45.7**	64.4	61.2
Alliance Pipeline US – shipper claim settlement	**2.8**	–	–
Offshore – property insurance recovery from 2005 hurricanes, net of repair costs	**–**	5.3	–
Earnings	**48.5**	69.7	61.2

Adjusted earnings from Gas Pipelines were $45.7 million for the year ended December 31, 2008 compared with $64.4 million for the year ended December 31, 2007. The decrease in adjusted earnings was substantially due to continuing natural production declines and lost revenue and clean up costs related to Hurricanes Gustav and Ike in Offshore.

Adjusted earnings from Gas Pipelines were $64.4 million for the year ended December 31, 2007 compared with $61.2 million for the year ended December 31, 2006. Adjusted earnings improved as construction of the Neptune Pipelines (within Offshore) was completed and stand-by fees were earned starting in the fourth quarter of 2007.

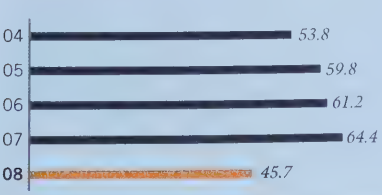
Gas Pipelines earnings were impacted by the following non-operating adjusting items:

- In the first quarter of 2008, Alliance Pipeline US received $2.8 million in proceeds from the settlement of a claim against a former shipper which repudiated its capacity commitment.
- Earnings for the year ended December, 2007 included insurance proceeds of $5.3 million related to the replacement of damaged infrastructure as a result of the 2005 hurricanes.

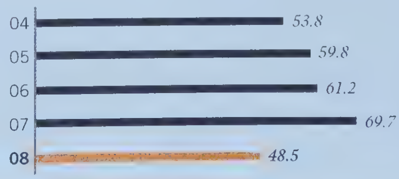
Revenues for the year ended December 31, 2008 were $359.3 million compared with $321.3 for the year ended December 31, 2007. The increase in revenues is due to higher Alliance Pipeline US tolls, Vector expansion and revenues from Neptune within Offshore.

Revenues for the year ended December 31, 2007 were $321.3 million compared with $345.9 million for the year ended December 31, 2006. The decrease in revenues was substantially due to the effect of the weaker U.S. dollar.

Gas Pipelines *Adjusted Earnings*
(millions of Canadian dollars)



Earnings
(millions of Canadian dollars)



Gas Pipelines

ALLIANCE PIPELINE US

The Alliance System (Alliance), which includes both the Canadian and U.S. portions of the pipeline system, consists of an approximately 3,000-kilometre (1,875-mile) integrated, high-pressure natural gas transmission pipeline system and an approximately 730-kilometre (455-mile) lateral pipeline system and related infrastructure. Alliance transports liquids-rich natural gas from northeast British Columbia and northwest Alberta to Channahon, Illinois. The pipeline has firm service shipping contract capacity to deliver 1.325 billion cubic feet per day (bcf/d). EIF, described under Sponsored Investments, owns 50% of the Canadian portion of the Alliance System.

Alliance connects with Aux Sable, a natural gas liquids extraction facility in Channahon, Illinois. The natural gas may then be transported to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to natural gas markets in the midwestern and northeastern United States and eastern Canada. Enbridge owns 42.7% of Aux Sable and its results are included under Gas Distribution and Services.

Results of Operations

Alliance Pipeline US adjusted earnings were $24.9 million for the year ended December 31, 2008 compared with $27.7 million for the year ended December 31, 2007. The decrease was primarily due to the weaker average U.S. dollar during 2008 and the depreciating ratebase.

The $2.0 million decrease in adjusted earnings between the years ended December 31, 2007 and 2006 was also primarily due to the weaker average U.S. dollar.

In the first quarter of 2008, Alliance Pipeline US received $2.8 million in proceeds from the settlement of a claim against a former shipper which repudiated its capacity commitment, resulting in increased earnings for the year ended December 31, 2008. Earnings for the years ended December 31, 2007 and 2006 equaled adjusted earnings.

Transportation Contracts

Alliance has long-term, take-or-pay contracts through 2015 to transport 1.305 bcf/d of natural gas or 98.5% of the total contracted capacity. Alliance has an additional 20 million cubic feet per day (mmcf/d) of natural gas contracted through 2010. These contracts permit Alliance to recover the cost of service, which includes operating and maintenance costs, the cost of financing, an allowance for income tax, an annual allowance for depreciation and an allowed return on equity. Each long-term contract may be renewed upon five years notice for successive one-year terms beyond the original 15-year primary term. Alliance Pipeline US operations are regulated by the FERC.

Depreciation expense included in the cost of service is based on negotiated depreciation rates contained in the transportation contracts, while depreciation expense in the financial statements is recorded on a straight-line basis at 4% per annum. Negotiated depreciation expense is generally less than the financial statement amount at the beginning of the contract and higher than straight-line depreciation in the later years of the shipper transportation agreements. This difference results in recognition of a long-term receivable, referred to as deferred transportation revenue that is expected to be recovered from shippers in subsequent years, beginning in 2009 for Alliance Pipeline US and 2012 for Alliance Pipeline Canada. As at December 31, 2008, $182.3 million (US$148.9 million) (2007 – $143.7 million; US$145.4 million) was recorded as deferred transportation revenue.

VECTOR PIPELINE

The Company provides operating services to, and holds a 60% joint venture interest in, Vector Pipeline, which transports natural gas from Chicago to Dawn, Ontario. Vector Pipeline has the capacity to deliver a nominal 1.2 bcf/d and is operating at or near capacity.

Vector Pipeline's primary sources of supply are through interconnections with the Alliance System and the Northern Border Pipeline in Joliet, Illinois. Approximately 58% of the long haul capacity of Vector Pipeline is committed to long-term, 15-year firm transportation contracts at rates negotiated with the shippers and approved by the FERC. The remaining capacity is sold at market rates and at various term lengths. Transportation service is provided through a number of different forms of service agreements such as Firm Transportation Service and Interruptible Transportation Service.

Results of Operations

Vector Pipeline earnings were $14.2 million for the year ended December 31, 2008 compared with $14.9 million for the year ended December 31, 2007. Earnings decreased as a result of increased taxes and by the weaker average U.S. dollar in 2008.

Vector Pipeline earnings were $14.9 million for the year ended December 31, 2007 compared with $13.4 million for the year ended December 31, 2006. Earnings improved, despite the stronger Canadian dollar, due to its late year expansion and lower operating costs in 2007.

STRATEGY

The Gas Pipelines strategy is developed based on the Company's forecast supply and demand for natural gas.

Supply and Demand for Natural Gas

The Chicago market is anticipated to enjoy robust supply as a result of increasing conventional production in the Rocky Mountains; expanding unconventional mid-continent production; and new supply from Gulf Coast liquefied natural gas (LNG) facilities. Surplus gas in Chicago may result in greater deliveries from this region to the Ontario market as traditional exports from Western Canada are expected to decline.

Further development of the oil sands projects in Alberta will increase the demand for natural gas as various extraction and upgrading processes require the use of natural gas. However, growth in natural gas demand in this sector may be tempered by alternative energy sources and delay or cancellation of oil sands projects.

Over time, the introduction of new supply from shale plays in northeast British Columbia and the U.S. Midcon region; increasing supply from the U.S. Rockies; LNG; and potential supply from the Alaska North Slope/Mackenzie Delta are expected to adequately supply the market and may provide opportunities for Enbridge to deliver this natural gas to markets.

Alliance Pipeline Recontracting Strategy

The Alliance Pipeline continues to be fully contracted on a firm service basis and is expected to run at or near full capacity until at least 2015 when existing long-term shipper contracts expire. Alliance Pipeline US is developing strategies to maximize its competitiveness, post-2015, in light of falling export production from Western Canada and the potential for surplus export pipeline capacity. Alliance is well placed to benefit from incremental unconventional volumes from shale plays in British Columbia and the northern gas development.

Rockies Alliance Pipeline

Alliance Pipeline US and Questar Overthrust Pipeline Company are jointly proposing a natural gas pipeline connecting the U.S. Rocky Mountain Region to the Chicago market hub. The proposed Rockies Alliance Pipeline (RAP) project is being developed in response to rapidly increasing supply from the U.S. Rockies region. RAP will enable producers, marketers and end-users to connect new gas supplies in the Greater Green River, Piceance, Uinta and Powder River basins with one of the largest and

fastest growing markets in North America. The RAP project will take advantage of existing infrastructure with both Questar and Alliance to provide competitive transportation to key market areas.

Upon in-service of the proposed project, RAP will initially provide 1.3 bcf/d of transportation capacity which is expandable to 1.7 bcf/d with the addition of compression. Provided that sufficient commercial support for the project is obtained in 2009, the pipeline is expected to be in-service in 2013.

Vector Pipeline Expansion

The Vector pipeline is undertaking a 0.1 bcf/d expansion in 2009 with potential further expansion in 2010-2011.

BUSINESS RISKS

The risks identified below are specific to Alliance Pipeline US and Vector Pipeline. General risks that affect the entire Company are described under Risk Management.

Supply and Demand

Advances in clean-coal technology and nuclear power as sources of power generation may reduce growth in natural gas demand over the longer term. However, demand is supported by declining U.S. traditional energy production, increasing need for clean burning natural gas and rising use of gas for power generation. Currently, pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline US and Vector Pipeline have been unaffected by this excess capacity environment mainly because of long-term capacity contracts extending to 2015. Vector Pipeline's interruptible capacity could be negatively impacted by the basis (location) differential in the price of natural gas between Chicago and Dawn, Ontario relative to the transportation toll.

Exposure to Shippers

The failure of shippers to perform their contractual obligations could have an adverse effect on the cash flows and financial condition of Alliance Pipeline US and Vector Pipeline. To reduce this risk, Alliance Pipeline US and Vector Pipeline monitor the creditworthiness of each shipper and receive collateral for future shipping tolls should a shipper's credit position not meet tariff requirements. These pipelines also have diverse groups of long-term transportation shippers, which include various gas and energy distribution companies, producers and marketing companies, further reducing the exposure.

Competition

Alliance Pipeline US faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects. Competing pipelines provide natural gas transportation services from the WCSB to distribution systems in the Midwestern United States. In addition, there are several proposals to upgrade existing pipelines serving these markets. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by the Alliance System. Shippers on Alliance Pipeline US have access to additional high compression delivery capacity at no additional cost, other than fuel requirements, serving to enhance Alliance Pipeline US' competitive position.

Vector Pipeline faces competition for pipeline transportation services to its delivery points from new or upgraded pipelines, which could offer transportation that is more desirable to shippers because of cost, supply location, facilities or other factors. Vector Pipeline has mitigated this risk by entering into long-term firm transportation contracts for approximately 58% of its capacity and medium-term contracts for the remaining capacity. These long-term firm contracts provide for additional compensation to Vector Pipeline if shippers do not extend their contracts beyond the initial term. The effectiveness of these mitigating factors is evidenced by the increased utilization of the pipeline since its construction, despite the presence of transportation alternatives.

Regulation

Both Vector Pipeline and Alliance Pipeline US operations are regulated by the FERC. On a yearly basis, following consultation with shippers, Alliance Pipeline US files its annual rates with the FERC for approval.

FERC has intensified its oversight of financial reporting, risk standards and affiliate rules and has issued new standards on managing pipeline integrity. The Company continues ongoing dialogue with regulatory agencies and participates in industry lobby groups to ensure it is informed of emerging issues in a timely manner.

Alberta Royalty Review

The Alberta Royalty Review as described under Liquids Pipelines is also applicable to both Vector Pipeline and Alliance Pipeline US.

ENBRIDGE OFFSHORE PIPELINES

Enbridge Offshore Pipelines is comprised of 11 natural gas gathering and FERC-regulated transmission pipelines in five major corridors in the Gulf of Mexico, extending to deepwater frontiers. These pipelines include almost 1,500 miles (2,400 kilometres) of underwater pipe and onshore facilities and transported approximately 1.7 bcf/d during 2008.

Results of Operations

Adjusted earnings for the year ended December 31, 2008 in Offshore were $6.6 million compared with $21.8 million for the year ended December 31, 2007. Offshore adjusted earnings decreased as a result of continuing natural production declines as well as approximately $11.0 million in lost revenue and clean up costs related to Hurricanes Gustav and Ike. These decreases were partially offset by stand-by fees on the Neptune oil and gas pipelines which came into service in the fourth quarter of 2007, as well as contributions from Atlantis and Thunderhorse platform volumes. Also, adjusted earnings for the year ended December 31, 2008 included approximately $2.0 million (2007 – $6.0 million) from business interruption insurance proceeds related to lost revenue in 2005 and 2006 as a result of the 2005 hurricanes.

Offshore adjusted earnings for the year ended December 31, 2007 were $21.8 million compared with $18.1 million for the year ended December 31, 2006. In 2007, earnings reflected the impact of a weaker U.S. dollar, continuing repair and inspection costs and expected continuing natural production declines on deliveries to the pipelines in 2007. Start up issues experienced by producers on key production platforms, resulting from the effects of the extreme 2005 hurricane season, delayed new sources of volumes during the year; however, volumes from the Atlantis platform started contributing to earnings at the end of 2007. Adjusted earnings for the year ended December 31, 2007 also included approximately $6.0 million from business interruption insurance proceeds related to lost revenue in 2005 and 2006 as a result of the 2005 hurricanes which was offset by approximately $0.7 million in repair costs.

Earnings for the year ended December 31,2007 included non-operating insurance proceeds of $5.3 million related to the replacement of damaged infrastructure as a result of the 2005 hurricanes.

Transportation Contracts

The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The throughput volume generally reflects the lease's maximum sustainable production. The transportation contracts allow the shippers to define a maximum daily quantity (MDQ), which corresponds with the expected production life. The contracts typically have minimum throughput volumes which are subject to take-or-pay criteria but also provide the shippers with flexibility given advance notice criteria to modify the projected MDQ schedule to match current deliverability expectations.

Increasingly, and reflecting recent setbacks from hurricanes, certain transportation contracts are beginning to reflect hurricane allowances to cover increased operating and repair costs.

The long-term transport rates established in the gathering and transmission service agreements are generally market-based but are established using a cost of service methodology, which includes operating cost, projected revenue generation directly tied to production deliverability and the appropriate cost of capital.

Strategy

While Offshore's longer-term growth potential is attractive, the magnitude and timing of this growth will very much depend on the ability and willingness of upstream producers to develop new plays. Offshore will utilize its inherent advantages (existing infrastructure, operational expertise, reputation and integrity of personnel) to compete for new pipeline development opportunities. Projects under construction are described below.

Shenzi Project

Enbridge has completed constructing a natural gas lateral to connect the new deepwater Shenzi field to existing Gulf of Mexico pipelines. The US$65.0 million 11-mile (18-kilometre), 12-inch diameter gas pipeline has capacity of 0.1 bcf/d. In-service is currently scheduled for the second quarter of 2009, concurrent with producer first volumes. The Shenzi lateral will deliver natural gas through the Company's 22%-owned Cleopatra Pipeline, the 50%-owned Manta Ray Pipeline and the 50%-owned Nautilus Pipeline.

Thunder Horse Production Project

During the second quarter of 2008, the first well in the Thunder Horse Project was put in service ahead of the producer's revised schedule, with production continuing to ramp-up as new wells are brought on to production. This significant third party-owned project, which will deliver natural gas into Offshore's gathering systems, has experienced startup issues due to the severe 2005 hurricanes which delayed its original in-service schedule.

Business Risks

The risks identified below are specific to Enbridge Offshore Pipelines. General risks that affect the Company as a whole are described under Risk Management.

Weather

Adverse weather, such as hurricanes, may impact Offshore financial performance directly or indirectly. Direct impacts may include damage to Offshore facilities resulting in lower throughput and inspection and repair costs. Indirect impacts include damage to third party production platforms, onshore processing plants and refineries that may decrease throughput on Offshore systems.

The Company continues to maintain an active risk management program that includes comprehensive insurance coverage. However, costs have increased in the form of higher insurance premiums and deductibles as well as longer waiting periods for business interruption claims. It is expected the incidence and severity of windstorm occurrences, and the Company's direct experience in the Gulf of Mexico, will dictate future costs and coverage levels in this region.

Competition

There is competition for new and existing business in the Gulf of Mexico. Offshore has been able to capture key opportunities, positioning it to more fully utilize existing capacity. Offshore serves a majority of the strategically located deepwater host platforms and its extensive presence in the deepwater Gulf of Mexico has Offshore well positioned to generate incremental revenues, with modest capital investment, by transporting production from sub-sea development of smaller fields tied back to existing host platforms. Offshore is also able to construct pipelines to transport crude oil, diversifying the risk of declining production, as demonstrated with the newly constructed Neptune crude oil lateral. Given rates of decline, Offshore Pipelines typically have available capacity resulting in significant and aggressive competition for new developments in the Gulf of Mexico.

Regulation

The transportation rates on many of Offshore's transmission pipelines are generally based on a regulated cost of service methodology and are subject to regulation by the FERC. These rates may be subject to challenge.

Other Risks

Other risks directly impacting financial performance include underperformance relative to expected reservoir production rates, delays in project start-up timing and capital expenditures in excess of those estimated. Capital risk is mitigated in some circumstances by having area producers as joint venture partners and through cost of service tolling arrangements. Start-up delays are mitigated by the right to collect stand-by fees.

CAPITAL EXPENDITURES

The Company expects to spend approximately $70 million in 2009 in the Gas Pipelines segment for ongoing capital improvements, core maintenance capital projects and expansion, including the projects described above. In 2008, the Company spent $136 million on capital expenditures in the Gas Pipelines segment which was consistent with expectations. Discussion of the Company's access to financing is included under Liquidity and Capital Resources.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 27.0% ownership interest in EEP and a 41.9% voting interest in EIF. Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each, including both organic growth and acquisition opportunities.

EARNINGS

(millions of Canadian dollars)	**2008**	2007	2006
Enbridge Energy Partners	**59.8**	47.3	36.5
Enbridge Income Fund	**41.1**	39.2	37.8
Adjusted Earnings	**100.9**	86.5	74.3
EEP – dilution gain on Class A unit issuance	**4.5**	11.8	–
EEP – unrealized derivative fair value gains/(losses)	**7.2**	(6.3)	6.5
EEP – gain on sale of Kansas Pipeline Company	**–**	3.0	–
EEP – impact of 2008 hurricanes and project write-offs	**(2.2)**	–	–
EIF – Alliance Canada shipper claim settlement	**1.3**	–	–
EIF – impact of tax rate changes	**–**	1.9	6.0
Earnings	**111.7**	96.9	86.8

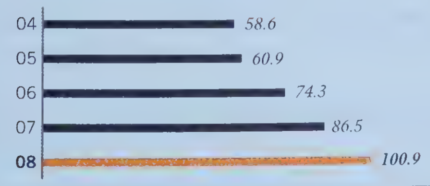
Adjusted earnings from Sponsored Investments were $100.9 million for the year ended December 31, 2008 compared with $86.5 million in 2007. Adjusted earnings increased as a result of the strong performance at EEP and increased distributions from EIF.

Adjusted earnings from Sponsored Investments were $86.5 million for the year ended December 31, 2007 compared with $74.3 million in 2006. The increase in adjusted earnings was primarily a result of the strong performance at EEP.

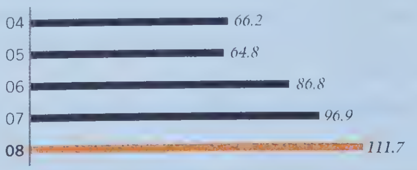
Sponsored Investments earnings were impacted by several non-operating adjusting items:

- Earnings in 2008 and 2007 included EEP dilution gains because Enbridge did not fully participate in EEP's Class A unit offerings, decreasing Enbridge's ownership interest in EEP to 14.6%. In December 2008, the Company purchased an additional US$500.0 million in Class A units increasing Enbridge ownership interest in EEP to 27.0%. Earnings from EEP included a change in the unrealized fair value on derivative financial instruments in each period.
- 2008 earnings from EEP included non-routine costs associated with Hurricanes Gustav and Ike, of which Enbridge's share is $0.8 million for the quarter and $1.6 million for the year-to-date, as well as the write-off of certain projects cancelled due to market conditions.
- Earnings from EIF for the year ended December 31, 2008 included proceeds of $1.3 million from the settlement of a claim against a former shipper on Alliance Canada which repudiated its capacity commitment.

Sponsored Investments *Adjusted Earnings*
(millions of Canadian dollars)



Earnings
(millions of Canadian dollars)



Enbridge Energy Partners – Liquids Pipelines

Revenues from Sponsored Investments include only revenues from EIF as the Company accounts for its interest in EEP using the equity method. For the year ended December 31, 2008, revenues were $297.5 million compared with revenues of $270.3 million for the year ended December 31, 2007. The increase in revenue was a result of increased revenues from both higher tolls at Alliance Canada and higher allowance oil revenue from the Saskatchewan System.

For the year ended December 31, 2007, revenues were $270.3 million compared with revenues of $254.7 million for the year ended December 31, 2006. The $15.6 million increase in revenue was a result of increased tolls on the Alliance and Saskatchewan System as well as a full year contribution from the wind assets purchased in Q4-2006.

ENBRIDGE ENERGY PARTNERS

EEP owns and operates crude oil and liquid petroleum transmission pipeline systems, natural gas gathering and related facilities and marketing assets in the United States. Significant assets include the Lakehead System, which is the extension of the Enbridge System in the U.S., natural gas gathering and processing assets in Texas, the mid-continent crude oil system, various interstate and intrastate natural gas pipelines and a crude oil feeder pipeline in North Dakota.

Results of Operations

Adjusted earnings from EEP were $59.8 million for the year ended December 31, 2008, compared with $47.3 million for the year ended December 31, 2007. EEP adjusted earnings increased as a result of higher incentive income and increased earnings at EEP due to higher gas and crude oil delivery volumes, tariff surcharges for recent expansions and additional revenue resulting from higher average crude oil prices associated with allowance oil. These increases were partially offset by increased operating and administrative costs and write downs of natural gas inventory to fair market value as a result of declines in the price of natural gas. Also, the Company's ownership interest in EEP increased to 27.0% in December 2008.

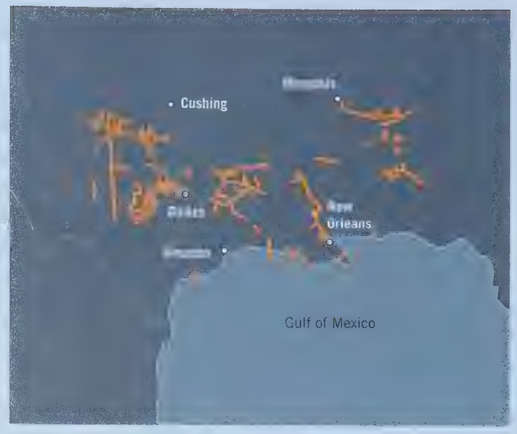
EEP earnings were favourably impacted by dilution gains because Enbridge did not fully participate in EEP's Class A unit offerings and by a change in the unrealized fair value on derivative financial instruments. Also, 2008 earnings from EEP included non-routine costs associated with Hurricanes Gustav and Ike, of which Enbridge's share is $1.6 million, as well as the write-off of certain projects cancelled due to market conditions.

Adjusted earnings from EEP were $47.3 million for the year ended December 31, 2007 compared with $36.5 million for the year ended December 31, 2006 despite the stronger Canadian dollar. The increase in adjusted earnings reflects Enbridge's larger average ownership interest in 2007 as well as higher incentive income, increased processing margins and higher volumes on principal natural gas and liquids systems that were partially offset by higher operating expenses.

Non-operating adjusting items impacted EEP earnings for fiscal 2007 and 2006 as follows:

- Dilution gains resulting from Enbridge not fully participating in Class A unit issuances.
- Unrealized derivative fair value gains and losses (losses in 2007 of $6.3 million; gains in 2006 of $6.5 million).
- Enbridge's $3.0 million share of the gain on the sale of Kansas Pipeline Company (KPC).

In the third quarter of 2006, EEP issued new Class C units. Enbridge participated in the offering and no dilution gains resulted. The Class C unit issuance increased Enbridge's ownership interest in EEP from 10.9% to 16.6%. Enbridge's average ownership interest in 2006 was 13.0%. In the second quarter of 2007, EEP issued partnership units. Because Enbridge did not fully participate in these offerings, dilution gains of $11.8 million resulted and Enbridge's ownership interest in the Partnership decreased from 16.6% to 15.1%. Enbridge's average ownership interest in 2007 was 15.5%. In March 2008, Enbridge did not participate in EEP's issuance of Class A units, resulting in a $4.5 million dilution gain and a decrease in ownership interest to 14.6%. In late 2008, Enbridge purchased 16.3 million Class A common units of EEP, resulting in an ownership increase to 27.0%. The Company's average ownership interest in EEP during 2008 was 15.7%



Enbridge Energy Partners – Gas Pipelines

Distributions

EEP makes quarterly distributions of its available cash to its common unitholders, including Enbridge. Under the Partnership Agreement, Enbridge, as general partner (GP), receives incremental incentive cash distributions, which represent incentive income, on the portion of cash distributions, on a per unit basis, that exceed certain target thresholds as follows:

	Unitholders Including Enbridge	Enbridge GP Interest
Quarterly Cash Distributions per Unit:		
Up to $0.59 per unit	98%	2%
First target – $0.59 per unit up to $0.70 per unit	85%	15%
Second target – $0.70 per unit up to $0.99 per unit	75%	25%
Over second target – cash distributions greater than $0.99 per unit	50%	50%

During 2006 EEP paid quarterly distributions of $0.925 per unit. In the first three quarters of 2007, EEP paid quarterly distributions of $0.925 per unit and effective November 2007, EEP increased quarterly distributions to $0.95 per unit. In the first two quarters of 2008 EEP paid quarterly distributions of $0.95 per unit and effective August 2008, EEP increased quarterly distributions to $0.99 per unit. Of the $75.7 million Enbridge recognized as earnings from EEP during 2008, 29% (2007 – 43%; 2006 – 37%) were general partner incentive earnings while 71% (2007 – 57%; 2006 – 63%) were Enbridge's limited partner share of EEP's earnings.

Strategy

Crude oil price volatility in 2008 has caused some crude oil producers to delay projects that were expected to commence over the next decade and this will cause EEP's expansion activities in and around EEP's Lakehead System to be more modest than experienced over the last several years. Significant liquidity tightening and volatility in the capital markets will necessitate a less aggressive capital program in EEP's natural gas business in the near term. During this period of volatility EEP will continue to focus primarily on development of the existing pipeline systems and those currently under construction. EEP will continue to evaluate strategic opportunities to further expand the service capabilities of its existing system.

In addition to the projects described under Liquids Pipelines, EEP is undertaking the following project:

North Dakota System Expansion

EEP is undertaking a further US$0.1 billion expansion of the North Dakota Pipeline System. The expansion is expected to increase system capacity from 110,000 bpd to 161,000 bpd and will consist of upgrades to existing pump stations, additional tankage as well as extensive use of drag reducing agents that are injected into the pipeline. The commercial structure for this expansion is a cost of service based surcharge that will be added to the existing transportation rates. Approval was received from the FERC in October 2008. The expansion is expected to be in-service in early 2010.

Business Risks

Financing Risk

EEP has made and expects to continue making substantial capital expenditures for the construction and development of crude oil and natural gas infrastructure. EEP intends to finance its future capital expenditures by utilizing cash from operations, borrowings under existing credit facilities and lastly from borrowings under the $500 million revolving credit agreement with Enbridge (see Liquidity and Capital Resources). EEP also expects to obtain permanent financing through the issuance of additional debt and equity securities, but may be unable to do so on attractive terms due to a number of factors including a lack of demand, poor economic conditions, unfavorable interest rates or its financial condition or credit rating at the time. In the event additional capital resources are unavailable; EEP may curtail construction and development activities, or be forced to sell some of its assets on an untimely or unfavorable basis in order to raise capital.

Supply and Demand

The profitability of EEP depends to a large extent on the volume of products transported on its pipeline systems. The volume of shipments on EEP's Lakehead System depends primarily on the supply of western Canadian crude oil and the demand for crude oil in the Great Lakes and Midwest regions of the United States and eastern Canada.

EEP's natural gas gathering assets are also subject to changes in supply and demand for natural gas, NGLs and related products. Commodity prices impact the willingness of natural gas producers to invest in additional infrastructure to produce natural gas. These assets are also subject to competitive pressures from third-party and producer-owned gathering systems.

Regulation

In the U.S., the interstate and intrastate gas pipelines owned and operated by EEP are subject to regulation by the FERC or state regulators and its revenues could decrease if tariff rates were protested. While gas gathering pipelines are not currently subject to active regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which EEP operates.

Market Price Risk

EEP's gas processing business is subject to commodity price risk for natural gas and NGLs. Historically, these risks have been managed by using physical and financial contracts, fixing the prices of natural gas and NGLs. Certain of these financial contracts do not qualify for cash flow hedge accounting and EEP's earnings are exposed to associated mark-to-market valuation changes.

ENBRIDGE INCOME FUND

EIF's primary assets include a 50% interest in Alliance Pipeline Canada and the 100%-owned Enbridge Saskatchewan System, both acquired from the Company in 2003. Alliance Pipeline Canada is the Canadian portion of the Alliance System previously described in the Gas Pipelines segment. The Enbridge Saskatchewan System owns and operates crude oil and liquids pipelines systems from producing fields in Southern Saskatchewan and Southwestern Manitoba connecting primarily with Enbridge's mainline pipeline to the United States.

Enbridge Income Fund

EIF also owns interests in three wind power generation projects purchased from Enbridge in October, 2006 and a business that develops and operates waste-heat power generation projects at Alliance Pipeline Canada compressor stations.

Results of Operations

Adjusted earnings from EIF were $41.1 million for the year ended December 31, 2008, compared with the prior year of $39.2 million. EIF adjusted earnings for the year ended December 31, 2008 reflected a 7.5% increase in the monthly distributions received from the Fund, effective May 2008, as well as a one-time special distribution of $0.024 per unit. On November 3, 2008, the Fund announced that it will increase regular monthly distributions by 11.6% to $0.096 per unit, effective with the distribution to be paid at the end of January 2009. This increase in adjusted earnings for the full year and in the fourth quarter was offset by higher tax on distributions received from EIF.

Adjusted earnings from EIF were $39.2 million for the year ended December 31, 2007, comparable with prior year adjusted earnings of $37.8 million.

In 2007, EIF recognized future taxes within entities that will become taxable in 2011 as a result of the enactment of Bill C-52, which is discussed under Tax Fairness Plan. This future tax increase was more than offset by the revaluation of future income tax obligations previously recorded as a result of tax rate reductions in the second and fourth quarters of 2007.

Tax Fairness Plan

On June 22, 2007, the "Tax Fairness Plan" income trust taxation legislation, Bill C-52, received Royal Assent. Under the enacted legislation, a distribution tax will be imposed on Enbridge Income Fund starting in 2011. The impact of the Tax Fairness Plan on the Fund's reported earnings was relatively small because most of the assets are rate regulated and future taxes are expected to be included in the approved rates charged to customers. However, as enacted in its present form, the Tax Fairness Plan will serve to reduce, all other things being equal, cash available for distribution by EIF commencing in 2011.

Incentive and Management Fees

Enbridge receives a base annual management fee of $0.1 million for management services provided to EIF plus incentive fees equal to 25% of annual cash distributions over $0.825 per trust unit. In 2008, the Company received incentive fees of $5.3 million (2007 – $3.5 million, 2006 – $2.4 million). The Company is the primary beneficiary of EIF through a combination of the voting units and a non-voting preferred unit investment and as such EIF is consolidated under variable interest entity accounting rules.

Strategy

EIF will maximize the efficiency and profitability of its existing assets, pursue organic growth and expansion opportunities, invest in the expansion activities within its assets including the Saskatchewan System expansion and Alliance Canada receipt facilities expansion as well as three new waste heat power generation projects. The following project is being undertaken by EIF:

Saskatchewan System Capacity Expansion

EIF will begin construction in 2009 on Phase II of the Saskatchewan System Capacity Expansion. This expansion consists of four separate projects that will reduce capacity constraints at a variety of locations. Collectively, the projects will increase capacity across the system by approximately 129,000 bpd at an estimated cost of approximately $100 million. Completion of the four capacity expansion projects is expected by the third quarter of 2010.

Business Risks

Risks for Alliance Pipeline Canada are similar to those identified for Alliance Pipeline US in the Gas Pipelines segment. The following risks relate to the Saskatchewan System. General risks that affect the Company as a whole are described under Risk Management.

Competition

The Saskatchewan System faces competition in pipeline transportation from other pipelines as well as other forms of transportation, most notably trucking. These alternative transportation options could charge rates or provide service to locations that result in greater net profit for shippers and thereby potentially reduce shipping on the Saskatchewan System or result in possible toll reductions. The Saskatchewan System manages exposure to loss of shippers by ensuring the shipping rates are competitive and by providing a high level of service. Further, the Saskatchewan System's right-of-way and expansion efforts have created a competitive advantage. The Saskatchewan System will continue to focus on increasing efficiencies and its expansion projects in order to meet its shippers' growing demand.

Demand for Services

Operations and tolls for the Saskatchewan Gathering and the Westspur Systems are, in general, based on volumes transported and are on terms similar to a common carrier basis with no specific on-going volume commitments. There is no assurance that shippers will continue to utilize these systems in the future or transport volumes on similar terms or at similar tolls.

GAS DISTRIBUTION AND SERVICES

Gas Distribution and Services consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario, the most significant being EGD. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, the Company's investment in Aux Sable (a natural gas fractionation and extraction business) and the Company's Energy Services businesses.

EARNINGS

(millions of Canadian dollars)	**2008**	2007	2006
Enbridge Gas Distribution	**123.3**	114.6	98.7
Noverco	**20.4**	18.6	18.7
Enbridge Gas New Brunswick (EGNB)	**14.7**	12.1	9.8
Other Gas Distribution	**7.6**	7.3	6.5
Energy Services	**16.8**	6.0	10.1
Aux Sable	**28.3**	10.6	25.8
Other	**(6.8)**	(0.3)	8.1
Adjusted Earnings	**204.3**	168.9	177.7
EGD – colder/(warmer) than normal weather	**23.1**	14.2	(36.9)
EGD – provision for one-time charges	**(2.8)**	–	–
EGD/Noverco – impact of tax changes	**–**	26.8	28.9
Noverco – dilution gain	**–**	–	4.0
Energy Services – unrealized derivative fair value gains/(losses)	**22.6**	(2.4)	–
Energy Services – SemGroup and Lehman bankruptcies	**(5.7)**	–	–
Aux Sable – unrealized derivative fair value gains/(losses)	**54.5**	(28.1)	–
Other – gain on sale of investment in Inuvik Gas	**4.6**	–	–
Earnings	**300.6**	179.4	173.7

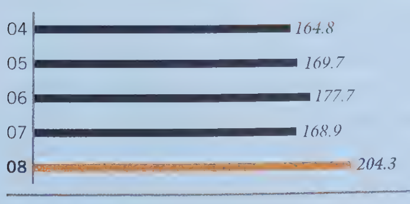
Adjusted earnings were $204.3 million for the year ended December 31, 2008 compared with $168.9 million for the year ended December 31, 2007. Earnings increased primarily due to customer growth and higher ancillary revenues at EGD, customer growth at EGNB and improved financial performance at Energy Services and Aux Sable.

Adjusted earnings were $168.9 million for the year ended December 31, 2007 compared with $177.7 million for the year ended December 31, 2006. Decreased earnings were due to lower contributions from Aux Sable and the Energy Services businesses, partially offset by customer growth and higher operating margins at EGD.

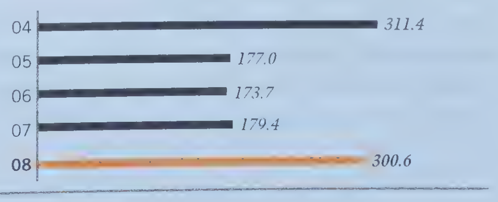
Gas Distribution and Services earnings were impacted by the following non-operating adjusting items:

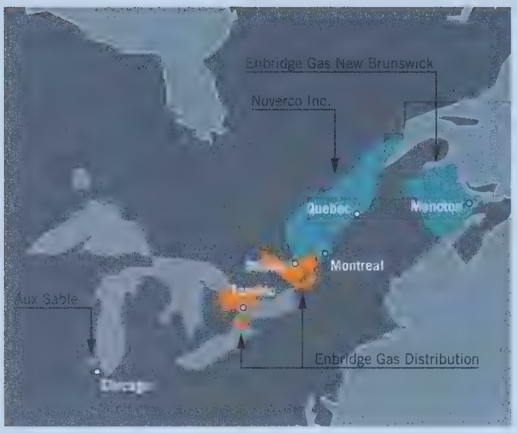
- EGD's earnings included a $2.8 million provision for one-time charges to better align certain operating practices with its strategy under incentive regulation (IR).
- Energy Services earnings reflected unrealized fair value gains in 2008 and losses in 2007 on derivative instruments, resulting from forward risk management positions used to "lock-in" the profitability of forward physical transportation and storage transactions at Tidal Energy.
- Energy Services earnings for 2008 also included a $5.7 million write-off as a result of bankruptcies by SemGroup and Lehman Brothers. The full amount of all such receivables has been provided for; however, some potential for partial recovery exists.
- Aux Sable year-to-date earnings reflected unrealized fair value gains in 2008 and losses in 2007 on derivative financial instruments used to mitigate the uncertainty of the Company's 2009 share of the contingent upside sharing mechanism which allows Aux Sable to share in natural gas processing margins in excess of certain thresholds. Similar to Energy Services, these non-cash gains arose due to the revaluation of financial derivatives used to "lock in" the profitability of forward contracted prices.

Gas Distribution and Services *Adjusted Earnings*
(millions of Canadian dollars)



Earnings
(millions of Canadian dollars)





Gas Distribution and Services

Revenues for the year ended December 31, 2008 were $14,279.6 million compared with $10,217.9 million for the year ended December 31, 2007. The increase in revenues was due to higher average commodity prices in Energy Services and EGD as well as unrealized derivative gains on risk managed forward positions.

Revenues for the year ended December 31, 2007 were $10,217.9 million compared with $8,973.2 million for the year ended December 31, 2006. The increase in revenues was a result of a significant increase in volumes transacted by Energy Services and, to a lesser extent, an increase in commodity prices for those transactions.

ENBRIDGE GAS DISTRIBUTION

EGD is Canada's largest natural gas distribution company and has been in operation for more than 160 years. It serves approximately 1.9 million customers in central and eastern Ontario, southwestern Quebec and parts of northern New York State. EGD's utility operations are regulated by the Ontario Energy Board (OEB) and by the New York State Public Service Commission.

Results of Operations

Adjusted earnings for the year ended December 31, 2008 were $123.3 million compared with $114.6 million for the year ended December 31, 2007. EGD's increased adjusted earnings for 2008 reflect early success during its first of five years under IR, specifically through customer growth and higher ancillary revenues.

EGD's earnings included a $2.8 million provision for one-time charges to better align certain operating practices with the EGD's strategy under IR.

Adjusted earnings for the year ended December 31, 2007 were $114.6 million compared with $98.7 million for the year ended December 31, 2006. Adjusted earnings in 2007 increased compared with 2006 because of customer growth, higher rates from the increased rate base and a higher deemed equity component of the rate base for regulatory purposes.

Incentive Regulation

Improving the regulatory environment is a key strategic thrust to provide greater operational and organizational flexibility. In 2008, EGD moved to an IR methodology. Under IR, the distribution revenue requirement and therefore rates, are based on a formulaic approach, using 2007 as the starting point.

The objectives of the IR plan are as follows:

- reduce regulatory costs;
- provide incentive for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates.

2009 Rate Adjustment Application

On September 26, 2008, EGD filed an application with the OEB to adjust rates for 2009 pursuant to the 2008 approved IR formula. Subject to OEB approval, the rate adjustment would be effective January 1, 2009. A settlement agreement containing all as applied for aspects of the formulaic component of the IR rate setting process was approved by the OEB on December 18, 2008.

2008 Rates

In 2007, EGD filed a rate application requesting a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The OEB approved the settlement agreement (the Settlement) with customer representatives.

EGD received a fiscal 2008 final rate order from the OEB on May 15, 2008, approving the implementation of a change in rates effective July 1, 2008, which enabled EGD to recover the approved revenues retroactively to January 1, 2008. The final rate order also approved a change in customer billing to increase the fixed charge portion and decrease the per unit volumetric charge, with no material annual earnings impact. The fixed charge portion will increase progressively over the IR term.

2007 Rates

EGD's rates for 2007 were set under a Cost of Service methodology that allowed the revenues to be set to recover EGD's forecast costs. Forecast costs included natural gas commodity and transportation, operation and maintenance, amortization, municipal taxes, income taxes and the debt and equity costs of financing the rate base. The rate base is EGD's investment in all assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under Cost of Service, it was the responsibility of EGD to demonstrate to the OEB the prudence of the costs it incurred or the activities it undertook.

Key elements of the OEB's 2007 rate decision, including issues previously settled and approved by the OEB, and a previous decision are summarized below:

Regulatory Year	Approved 2007
Rate base *(millions of Canadian dollars)*	$3,745.7
Deemed common equity for regulatory purposes	36%
Rate of return on common equity	8.39%

For 2007, EGD was granted a 1% increase in the equity component of its deemed capital structure. The 36% deemed equity level is better reflective of changes in EGD's current business and financial risk relative to the earlier deemed equity level of 35%.

Strategy

EGD's vision is to become North America's leading energy distribution company. To achieve this vision, EGD has outlined the following strategic objectives:

- achieve top decile safety performance;
- enhance operational and financial governance effectiveness;
- deliver shareholder value;
- maintain a healthy and productive work environment; and
- enhance customer and stakeholder relationships.

One of EGD's major strategic initiatives is to continue to enhance the effectiveness of the business operations under IR, including rationalizing capital investment and increasing productivity. In addition, EGD will seek new growth opportunities, including growth in its core natural gas distribution business, investment in new infrastructure for power generation and fuel switching, development and delivery of energy efficiency programs and billing services for third parties, as well as the development of new natural gas storage space.

Customer Growth

Another major strategic initiative is enhancing customer growth. EGD added over 41,000 new customers during the year ended December 31, 2008 (over 43,000 in the year ended December 31, 2007). In addition to traditional gas distribution growth expected, new earnings growth opportunities include investment in new infrastructure for power generation, fuel switching, implementation of turboexpanders on the natural gas distribution system, development and delivery of energy efficiency programs and billing services for third parties, as well as development of new natural gas storage space.

Storage Project

The Company provides storage services to wholesale storage market participants. In 2008, the Company provided approximately 3 million gigajoules of high deliverability storage capacity to these customers. Management continues to monitor the storage market and expects to develop new storage capacity when it is economically appropriate.

Customer Care and Customer Information System

In April 2007, EGD entered into new five-year customer care services contracts with third-party service providers for meter reading, billing, billing administration, call handling and collections. The total cost of the contracts is approximately $274 million over the five-year term. EGD is also working towards implementing a new Customer Information System, which will replace the legacy system by July 2009 and at an estimated cost of $119 million, in order to meet regulatory requirements and to meet the need for a more robust and technologically up-to-date system.

The OEB has approved a six-year rate recovery arrangement for customer care services and a 10 year recovery of the $119 million to be invested in the new CIS.

Capital Expenditures

EGD's capital expenditures in 2008 were $411 million and are expected to be $389 million in 2009 as EGD completes laterals for new power generating facilities, and builds its CIS system discussed above.

Legal Proceedings

Bloor Street Incident

EGD had been charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto on April 24, 2003. On October 25, 2007, all of the TSSA and OHSA charges laid against EGD were dismissed by the Ontario Court of Justice. The decision has been appealed by the Crown to the Ontario Superior Court of Justice. The appeal is scheduled to be heard by the Court during November 2009. The maximum possible fine upon conviction would not result in any material financial impact on EGD.

EGD has also been named as a defendant in a number of civil actions related to the explosion. All significant civil actions have been settled without any material financial impact on EGD. A Coroner's Inquest in connection with the explosion is also possible.

Harper Gardens Incident

On February 14, 2007, an explosion and fire occurred at a residence on Harper Gardens in Toronto. The home was destroyed and a resident of the home was killed. A natural gas contractor working in the home at the time of the explosion was seriously injured. Several public authorities commenced investigations in connection with the incident. The Company has also been named as a defendant in civil actions related to the incident, but does not expect these actions to result in any material financial impact.

Gas Distribution and Services – Number of Active Customers *(thousands)*

EGD added over 41,000 customers in 2008 (over 43,000 in 2007).

GST Overpayment

In December 2007, EGD discovered that it had remitted excess GST to the Canada Revenue Agency (CRA). In respect of certain months within the 2003 to 2005 calendar year periods, the amount of such overpayment is approximately $40 million. EGD expects that it will recover the overpayment from the CRA during 2009.

Business Risks

The risks identified below are specific to EGD. General risks that affect the Company as a whole are described under Risk Management.

Regulatory Risk

The formula currently approved by the OEB for determination of the return on equity, which is embedded and escalated within rates over the IR period, is based on the OEB's current risk assessment of EGD for the 2007 fiscal year.

The Settlement allows certain categories of expense, added at Cost of Service base amounts, and uncontrollable external factors in the IR formula, which will permit EGD to recover, with OEB approval, certain costs that are beyond management control, but are necessary for the maintenance of its services. The Settlement also includes a mechanism to end the IR plan and return to cost of service if there are significant and unanticipated developments that threaten the sustainability of the IR plan. The above noted terms set out in the Settlement mitigate EGD's risk to factors beyond management's control.

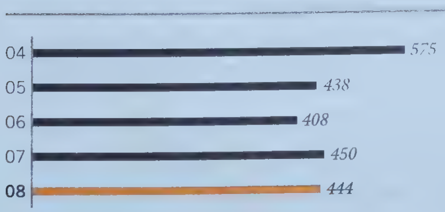
EGD does not profit from the sale of the natural gas commodity nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to customers until the OEB approves its refund or collection. EGD monitors the balance and its potential impact on customers and will request interim rate relief that will allow EGD to recover or refund the natural gas commodity cost differential. EGD has a quarterly rate adjustment mechanism in place for the natural gas commodity. This allows for the quarterly adjustment of rates to reflect changes in natural gas commodity prices. Adjustments are subject to prior approval by the OEB.

Volume Risks

Since customers are billed on both a fixed charge and on a volumetric basis, EGD's ability to collect its total revenue requirement depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts will be reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and the growth of customers.

Weather is a significant driver of delivery volumes, given that a significant portion of EGD's customer base uses natural gas for space heating. In recent years, earnings have been impacted given the unusual pattern of weather during the year.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continues to place downward pressure on consumption. In addition, conservation efforts by customers to partially mitigate the impact of higher natural gas commodity prices further contribute to the decline in annual average consumption.



Volume of Gas Distributed *(billion cubic feet)*

Gas volumes distributed reflect the growing number of active customer and the impact each year of warmer than normal or colder than normal weather. The 2004 volumes reflects the 15-month period.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 79% (2007 – 78%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn the return on equity due to other forecast variables such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector.

This distribution volume risk for general service customers is mitigated by the use of appropriate forecasting models and through the average use true-up variance account that was established under the IR Settlement Agreement. This variance account enables recovery from or repayment to customers of amounts representing variances in the actual and forecast average use by general service customers. EGD is still at distribution volume risk for contract customers.

NOVERCO

Enbridge owns an equity interest in Noverco through ownership of 32.1% of the common shares and a cost investment in preferred shares. Noverco is a holding company that owns approximately 71.0% of Gaz Metro Limited Partnership (Gaz Metro), a publicly traded gas distribution company operating in the province of Quebec and the state of Vermont.

Results of Operations

Noverco adjusted earnings were $20.4 million for the year ended December 31, 2008, comparable to $18.6 million for the year ended December 31, 2007 and $18.7 million for the year ended December 31, 2006.

In 2006, earnings were impacted by a non-operating adjusting item of a $4.0 million as a result of the recognition of a dilution gain from a Gaz Metro unit issuance in which Noverco did not participate.

Weather variations do not affect Noverco's earnings as Gaz Metro is not exposed to weather risk. A significant portion of the Company's earnings from Noverco is in the form of dividends on its preferred share investment, which is based on the yield of 10-year Government of Canada bonds plus 4.34%.

ENBRIDGE GAS NEW BRUNSWICK

The Company owns 70.9% of, and operates, Enbridge Gas New Brunswick, which owns the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 9,400 customers. Approximately 725 kilometres (450 miles) of distribution main has been installed with the capability of attaching approximately 30,000 customers.

Results of Operations

EGNB earnings were $14.7 million for the year ended December 31, 2008 compared with $12.1 million for the year ended December 31, 2007 and $9.8 million for the year ended December 31, 2006. Earnings were higher in 2008 and 2007 as a result of franchise customer growth.

EGNB is regulated by the New Brunswick Energy and Utilities Board (EUB). As it is currently in the development period, EGNB's cost of service exceeds its distribution revenues. The EUB has approved the deferral of the difference between distribution revenues and the cost of service during the development period for recovery in future rates. This recovery period is expected to start in 2010 and end no sooner than December 31, 2040. On December 31, 2008, the regulatory deferral asset was $132.7 million (2007 – $117.7 million).

ENERGY SERVICES

Energy Services includes Gas Services and Tidal Energy, the Company's energy marketing businesses. Gas Services markets natural gas to optimize Enbridge's commitments on the Alliance and Vector

Pipelines. It also has a growing business of providing fee-for-service arrangements for third parties, leveraging its marketing expertise and access to transportation capacity. Capacity commitments as of December 31, 2008 were 32.7 mmcf/d on the Alliance Pipeline (2.5% of total capacity) and 144 mmcf/d on Vector Pipeline (12.0% of total capacity). Capacity commitments as of December 31, 2007 were 32.2 mmcf/d on the Alliance Pipeline (2.0% of total capacity) and 162.1 mmcf/d on Vector Pipeline (16.4% of total capacity).

Earnings from Gas Services are dependent upon the basis (location) differentials between Alberta and Chicago, for Alliance Pipeline, and between Chicago and Dawn, for Vector Pipeline. To the extent the cost of transportation on these two pipelines exceeds the gas commodity basis differential, earnings will be negatively affected.

Tidal Energy provides crude oil and NGLs marketing services for the Company and its customers in a full range of condensate and crude oil types including light sweet, light and medium sours and several heavy grades. Tidal Energy transacts at many of the major North American market hubs and provides its customers with a variety of programs including flexible pricing arrangements, hedging programs, product exchanges, physical storage programs and total supply management, through the analysis and implementation of different transportation options, reduced quality differentials and tariff structures, and utilizing risk management pricing options. Tidal Energy's business involves buying, selling and storing large quantities of crude oil. Tidal Energy is primarily a physical barrel marketing company and in the course of its market activities, physical receipt or delivery shortfalls can create modest commodity exposures. Any open positions created from this physical business are tightly monitored and must comply with the Company's formal risk management policies.

Results of Operations

Adjusted earnings from Energy Services were $16.8 million for the year ended December 31, 2008 compared with $6.0 million for the year ended December 31, 2007. Energy Services adjusted earnings increased due to higher margins captured on storage and transportation contracts as well as increased transportation and storage volumes in Tidal Energy.

Energy Services earnings were impacted by several non-operating adjusting items; unrealized fair value gains on derivative instruments, resulting from forward risk management positions used to "lock-in" the profitability of forward physical transportation and storage transactions at Tidal Energy, and a $5.7 million write-off as a result of bankruptcies by SemGroup and Lehman Brothers. The full amount of all such receivables has been provided for and some potential for partial recovery exists.

Adjusted earnings from Energy Services were $6.0 million for the year ended December 31, 2007 compared with $10.1 million for the year ended December 31, 2006. The decrease in adjusted earnings was due to outstanding storage transactions in Tidal Energy that were negatively impacted by rising crude oil prices. Tidal Energy buys crude oil, stores it and sells it forward at a higher price, locking in a profit on the transaction. However, during the life of the transaction, Tidal Energy may hold the oil held in storage and use it to satisfy a new forward sale at an additional deferred profit. Tidal Energy then purchases oil at spot prices to satisfy the original sale transaction. As a result, losses will be recognized in periods of rising oil prices and profitability will be deferred until the original transaction settles.

AUX SABLE

Enbridge owns 42.7% of Aux Sable, a NGLs extraction and fractionation business near Chicago. Aux Sable owns and operates a plant at the terminus of the Alliance System. The plant extracts NGLs from the energy-rich natural gas transported on the Alliance System, as necessary, to meet the heat content requirements of local distribution companies, which require natural gas with less NGLs, or lower heat content, and to take advantage of positive commodity price spreads.

Aux Sable has an agreement with BP Products North America Inc. to sell its NGLs production to BP. In return, BP pays Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified natural gas processing margin thresholds (the upside sharing mechanism). In addition, BP compensates Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable

facilities subject to certain limits on capital costs. BP supplies, at its cost, all make-up gas and fuel supply gas to the Aux Sable facilities and is responsible for the capacity on the Alliance Pipeline held by an Aux Sable affiliate, at market rates. The agreement is for an initial term of 20 years, commencing January 1, 2006 and may be extended by mutual agreement for 10-year terms. If cumulative losses exceed a certain limit, BP will have the option to terminate the agreement, although Aux Sable has the right to reduce such losses to avoid termination.

Results of Operations

Adjusted earnings for the year ended December 31, 2008 were $28.3 million compared with $10.6 million for the year ended December 31, 2007. Aux Sable adjusted earnings increased due to strong fractionation margins and enhanced plant performance, in addition to favourable risk management positions, which enabled the Company to recognize earnings from the upside sharing mechanism.

Aux Sable year-to-date earnings reflected unrealized fair value gains on derivative financial instruments used to risk manage the Company's 2009 share of the contingent upside sharing mechanism, which allows Aux Sable to share in natural gas processing margins in excess of certain thresholds. Similar to Energy Services, these non-cash, non-operating gains arose due to the revaluation of financial derivatives used to "lock in" the profitability of forward contracted prices.

Adjusted earnings for the year ended December 31, 2007 were $10.6 million compared with earnings of $25.8 million for the year ended December 31, 2006. The decrease was due to lower fractionation spreads in 2007 compared with 2006 as well as the weaker U.S. dollar.

Aux Sable's 2007 reported earnings included $28.1 million of unrealized derivative fair value losses related to the Company's share of 2008 contingent upside sharing revenue.

OTHER

The adjusted operating loss in Other was $6.8 million in 2008 compared with $0.3 million in 2007. Losses in Other for the year ended December 31, 2008 primarily reflected lower earnings from CustomerWorks which resulted from the April 2007 transition of customer care services related to EGD to a third-party service provider pursuant to an OEB recommendation.

Adjusted operating loss in Other was $0.3 million in 2007 compared with adjusted earnings of $8.1 million in 2006. Lower earnings in 2007 were primarily due to the change at Customer Works.

Strategy

Other Natural Gas Distribution Strategies

Enbridge intends to pursue natural gas business development opportunities complementary to the existing gas distribution and services businesses through:

- developing LNG regasification projects and related pipeline infrastructure;
- pursuing marketing and storage opportunities that optimize existing assets; and
- exploring gas-fired generation opportunities that are underpinned by long-term contracts and improve the utilization of existing assets. The approach is to slowly build this business and utilize partners to share development risks.

Further to this strategy, Enbridge is developing a number of projects, which are described below.

Rabaska LNG Facility

In the second quarter of 2008, the Rabaska partners signed a Letter of Intent with Gazprom Marketing & Trading USA, Inc. (GMTUSA) regarding supply for the proposed Rabaska LNG regasification terminal. The Letter of Intent outlines the major terms under which GMTUSA will become an equity partner in the proposed Rabaska LNG project and will contract for 100% of the Rabaska terminal's capacity. The Rabaska LNG facility has all major authorizations, including project and land use approvals from the province of Quebec in October 2007 and federal government approvals in March 2008. Pending commercial advancement of GMTUSA's upstream development, the project is schedule to be in service in 2013 or 2014.

NetThruPut

In 2007, the Company and its partner in NetThruPut (NTP) entered into an agreement with the TSX Group granting the TSX Group the option to purchase NTP, an internet-based crude oil trading and clearing platform. Proceeds of $9.5 million were received from the sale of the option. The option may be exercised at a time after March 15, 2009 for a price of approximately $60 million. The agreement also provides the Company and its partner in NTP an option to sell NTP under the same terms to the TSX Group. The Company has a 52% ownership interest in NTP.

CAPITAL EXPENDITURES

Capital expenditures in Gas Distribution and Services, excluding EGD, were $73 million in 2008 (2007 – $86 million). Capital expenditures for 2009 are expected to be $93 million.

INTERNATIONAL

International includes the Company's investment in, and management of, Oleoducto Central S.A. (OCENSA), a crude oil pipeline in Colombia, as well as earnings from the Company's interest in Compañía Logística de Hidrocarburos CLH, S.A., Spain's largest refined products transportation and storage business, prior to its sale. Other includes administration and business development.

EARNINGS

(millions of Canadian dollars)	**2008**	2007	2006
OCENSA/CITCol	**32.7**	32.9	33.9
CLH	**24.7**	60.4	54.5
Other	**(5.3)**	(3.4)	(5.2)
Adjusted Earnings	**52.1**	89.9	83.2
CLH – gain on sale of investment	**556.1**	–	–
CLH – gain on land sale	**–**	5.2	–
Earnings	**608.2**	95.1	83.2

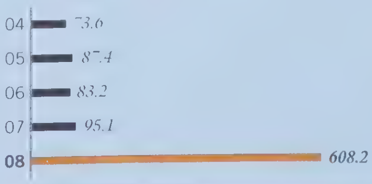
Adjusted earnings for the year ended December 31, 2008 were $52.1 million compared with $89.9 million for the year ended December 31, 2007. International's adjusted earnings decreased for the year ended December 31, 2008 as a result of the sale of CLH on June 17, 2008, which also resulted in a non-operating gain on disposal of $556.1 million increasing 2008 earnings to $608.2 million compared with $95.1 million in 2007.

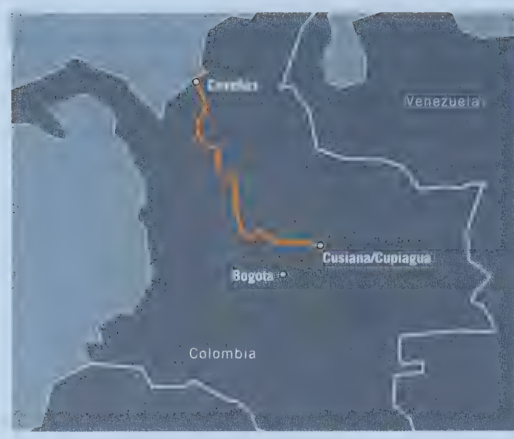
Adjusted earnings for the year ended December 31, 2007 were $89.9 million compared with $83.2 million for the year ended December 31, 2006. The increase in adjusted earnings was due to stronger operating earnings in CLH as a result of higher transported volumes, an increase in operating revenues from complimentary businesses, lower income taxes as a result of a tax rate reduction in Spain and lower business development costs in Other.

Earnings in 2007 included a $5.2 million gain on the sale of land within CLH.

International *Adjusted Earnings*
(millions of Canadian dollars)

Earnings
(millions of Canadian dollars)





Colombia – OCENSA

OCENSA/CITCol

The Company owns a 24.7% interest in OCENSA, an investment on which the Company earns a fixed return. OCENSA is one of two main crude oil export pipelines within Colombia. Through a 100% owned entity, CITCol, the Company manages the pipeline and earns a fee for this service, which includes incentives for operating performance. In 2007, OCENSA made the final payments with respect to its original US$1.6 billion project debt financing. With no further debt servicing obligations OCENSA may opt to begin returning the Company's initial equity capital starting in 2009, in accordance with the terms of the project agreements.

CLH

On June 17, 2008, the Company sold its 25% equity interest in CLH. Proceeds from the disposal of the CLH investment were applied toward funding the Company's North American growth projects.

STRATEGY

The Company's strategy internationally has always been patient and opportunistic. Two staggered investments in Colombia and Spain over the course of 13 years, and the recent profitable sale of the Spanish investment, demonstrate this approach. While the International portfolio has recently decreased in size, the Company continues to view this business segment as attractive and it could potentially once again become a meaningful portion of the Company. International investments provide unique diversification and potentially premium risk-adjusted returns, provided they meet the Company's stringent investment criteria.

BUSINESS RISKS

The International business is subject to risks related to political and economic instability, currency volatility, market and supply volatility, government regulations, foreign investment rules, security of assets and environmental considerations. The Company assesses and monitors international regions and specific countries on an ongoing basis for changes in these risks. Risks are mitigated by a combination of Enbridge's governance involvement, contractual arrangements, influence in operation of the assets, regular analysis of country risk as well as foreign currency hedging and insurance programs.

Competition

The Company's current strategic focus may constrain the level of resources and attention focused on opportunities in the broader international market. International has mitigated the risk by monitoring and investigating international investment opportunities.

CORPORATE

Corporate includes new business development activities and investing and financing activities, including general corporate investments and financing costs not allocated to the business segments. This segment also includes new platforms currently being pursued by the Company including renewable energy (wind and solar), CO2 transportation and sequestration and Pathfinding initiatives. Pathfinding initiatives include pursuing investment in smaller start-up entities where that investment will enable the development of promising new technologies that complement the Company's core operations.

(millions of Canadian dollars)	**2008**	2007	2006
Adjusted Corporate Costs	**(57.8)**	(59.2)	(77.7)
Gain on sale of corporate aircraft	**4.9**	–	–
U.S. pipeline tax decision	**(32.2)**	–	–
Unrealized derivative fair value gains	**26.2**	–	–
Asset impairment loss	**(17.3)**	–	–
Impact of tax changes	–	31.1	14.0
Costs	**(76.2)**	(28.1)	(63.7)

Corporate costs before adjusting items were $57.8 million for the year ended December 31, 2008, comparable with $59.2 million for the year ended December 31, 2007.

2008 corporate costs were impacted by the following non-operating adjusting items:

- A $4.9 million gain on the sale of a corporate aircraft.
- An unfavourable court decision related to the tax basis of previously owned U.S. pipeline assets which resulted in the recognition of a $32.2 million income tax expense.
- Unrealized fair value gain on derivative financial instruments, resulting from forward risk management positions to minimize the volatility of future U.S. dollar earnings across the Company.
- Asset impairment loss related to the write-off of goodwill related to the Company's Ontario wind power assets as well as a write-down of the Company's investment in NSolv, a technology development venture.

Corporate costs before adjusting items were $59.2 million for the year ended December 31, 2007, compared with $77.7 million in 2006. Corporate costs decreased due to lower interest expense resulting from decreased average debt balances throughout 2007 as a result of the equity issuance in the first quarter. As well, expenditures on corporate development activity decreased because of the Company's focus on organic growth. Corporate costs were impacted by the non-operating adjusting item of favorable legislated tax changes in both years.

STRATEGY

In the longer term, developing new business platforms will be important to maintaining growth and diversification within the Company. New platforms currently being pursued include renewable energy (wind and solar), CO2 transportation and sequestration and Pathfinding initiatives. The Company is currently undertaking the following projects:

Ontario Wind Project

Construction of the 190-megawatt Enbridge Ontario Wind Power Project, located in the Municipality of Kincardine on the Eastern shore of Lake Huron in Ontario, was completed in the fourth quarter of 2008. Although turbines were fully available for operation at the end of 2008, staging of turbine operations was implemented to ensure safe and reliable operations for the wind project. As of December 31, 2008, 65 of the 115 wind turbines (56.5%) were operating and reliably delivering power to the grid. The remaining 50 turbines will be phased into service with all turbines targeted to deliver power to the grid by early February 2009. The final capital cost of the project is estimated at $481 million.

Alberta Saline Aquifer Project

The 38-member Alberta Saline Aquifer Project (ASAP) is on track to complete Phase I in Spring 2009. Phase I has identified specific reservoir locations that offer the potential for long term carbon dioxide sequestration and has developed a preliminary design and cost estimate for a carbon dioxide sequestration pilot. Following receipt of regulatory approvals, the ASAP team anticipates that it will begin Phase II, constructing the pilot project, including drilling of the injection and monitoring wells in 2009, with injections of carbon dioxide beginning in 2010. Phase III will involve expanding the pilot project to a large-scale, long-term commercial operation. ASAP, spearheaded by Enbridge, is the largest project of its kind in North America and will play a major role in advancing industry and government's knowledge of carbon dioxide sequestration.

Hybrid Fuel Cell Power Plant

In October 2008, the Company and FuelCell Energy Inc. announced the opening of the world's first hybrid fuel cell power plant. The plant, which will produce 2.2 megawatts of environmentally preferred, ultra-clean electricity, or enough power for approximately 1,700 residences, is also the first multi-megawatt commercial fuel cell to operate in Canada. Support for this $10 million project was provided by both the Canadian and Ontario Governments. The Company, as the exclusive distributor of the hybrid fuel cell technology, will be promoting the technology to other natural gas distribution companies throughout North America.

CAPITAL EXPENDITURES

Capital expenditures in Corporate were $117 million in 2008 (2007 – $159 million). Capital expenditures for 2009 are expected to be $80 million.

LIQUIDITY AND CAPITAL RESOURCES

The Company will utilize cash from operations and the issuance of commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures and pay common share dividends throughout 2009. At December 31, 2008, the Company had $6.5 billion (2007 – $5.6 billion) of committed credit facilities excluding the Southern Lights project financing described below, of which $3.4 billion was drawn or used to backstop commercial paper. The Company has provided EEP with a revolving credit agreement for up to US$0.5 billion resulting in net available liquidity at December 31, 2008 for the Company of $3.0 billion, inclusive of cash and cash

equivalents of $0.5 billion. The following table provides details of the company's credit facilities at December 31, 2008.

(millions of Canadian dollars)	Expiry Dates	Total Facilities	Credit Facility Draws	Commercial Paper Backstop	Available
Liquids Pipelines	2010 - 2011	1,300.0	525.5	–	774.5
Gas Distribution and Services	2009 - 2010	1,014.7	11.1	874.5	129.1
Corporate [1]	2010 - 2013	4,185.8	962.3	1,075.1	2,148.4
		6,500.5	1,498.9	1,949.6	3,052.0
Southern Lights project financing [2]	2014	2,028.1	1,358.9	–	669.2
Credit facilities		8,528.6	2,857.8	1,949.6	3,721.2

1 *Total facilities exclusive of $49.0 million commitment of Lehman Brothers Bank given the bankruptcy filing of its parent in September 2008.*

2 *Total facilities inclusive of $140.2 million which is available if certain conditions related to the project are met.*

In January 2009, a credit facility established in December 2008, was increased by $0.2 billion to $0.5 billion as a result of new lender commitments, providing additional liquidity. The Company will look to access the capital markets for long-term financing as projects approach the in service date and to manage overall liquidity. The Company was successful in accessing $0.5 billion from the debt capital markets in the fourth quarter of 2008, as noted below in Financing Activities.

During 2008, the Company established $0.4 billion and US$1.3 billion in project financing that is non-recourse to the Company, for the Canadian and U.S. components of the Southern Lights project. These facilities are sufficient to fund the debt component of the Southern Lights financing and comprise construction, cost overrun and letter of credit facilities that mature in 2014, which is four years beyond the expected completion date of the project. At December 31, 2008, $0.3 billion and US$0.9 billion were drawn under the project financing facilities.

The Company's credit facility agreements include standard default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As in prior years, the Company expects to continue to comply with these provisions and therefore not trigger any early repayments.

The Company continues to manage its debt to capitalization ratio to maintain a strong balance sheet. The Company's debt to capitalization ratio at December 31, 2008, including short-term borrowings but excluding non-recourse debt and project financing was 60.7%, compared with 62.7% at the end of 2007. Including all debt, the capitalization ratio was 66.6% compared with 66.5% at the end of 2007.

The Company invests its surplus cash in short-term investment grade instruments with credit worthy counterparties. At December 31, 2008, there were $474.2 million of short-term investments intended to enhance access to short-term liquidity given the recent market turbulence. Short-term investments were $87.8 million in 2007 and $66.8 million in 2006.

Excluding current maturities of long-term debt, the Company has a positive working capital position, consistent with December 31, 2007.

(millions of Canadian dollars)	2008	2007
Cash and cash equivalents	**541.7**	166.7
Accounts receivable and other	**2,322.5**	2,388.7
Inventory	**844.7**	709.4
Short-term borrowings	**(874.6)**	(545.6)
Accounts payable and other	**(2,411.5)**	(2,213.8)
Interest payable	**(101.9)**	(89.1)
Working capital	**320.9**	416.3

Changes in commodity prices impact accounts receivable, inventory and accounts payable at Tidal Energy and EGD.

OPERATING ACTIVITIES

Cash from operating activities increased to $1,387.7 million for the year ended December 31, 2008 from $1,351.6 million for the year ended December 31, 2007 and $1,315.3 million for the year ended December 31, 2006.

(millions of Canadian dollars)	**2008**	2007	2006
Earnings net of non-cash items	**1,398.0**	1,358.0	1,191.6
Changes in operating assets and liabilities	**(10.3)**	(6.4)	123.7
Cash Provided by Operating Activities	**1,387.7**	1,351.6	1,315.3

Cash provided by earnings net of non-cash items, was $1,398.0 million for the year ended December 31, 2008, compared with $1,358.0 million and $1,191.6 million for 2007 and 2006, respectively. The increased earnings from operating activities in 2008 and 2007 resulted primarily from higher earnings at EGD. Cash from operating activities are stable and predictable for the Company given the regulated nature of the assets.

There are no material restrictions on the Company's cash with the exception of proportionately consolidated joint venture cash of $73.6 million, which cannot be accessed until distributed to the Company.

Changes in operating assets and liabilities were $130.1 million lower in 2007 compared with 2006. This decrease primarily resulted from increased accounts receivable at EGD at December 31, 2007 due to the relatively colder weather experienced during the final billing periods of the year.

INVESTING ACTIVITIES

In 2008, cash used for investing activities was $2,852.9 million compared with $2,228.8 million in 2007, an increase of $624.1 million. In 2008, the Company had increased capital expenditures primarily due to growth projects such as Southern Lights, Alberta Clipper and Line 4 as well as core maintenance expenditures incurred primarily at EGD and Enbridge System. In November 2008, the Company increased its investment in EEP by subscribing for 16.3 million Class A common units for US$500.0 million. These expenditures were partially offset by the proceeds from the sale of Enbridge's investment in CLH in 2008.

Cash used for investing activities for the year ended December 31, 2007 was $2,228.8 million compared with $1,597.6 million in 2006 as a result of increased capital expenditures primarily due to growth projects such as Southern Lights, Waupisoo Pipeline and Ontario Wind Project as well as core maintenance expenditures incurred primarily at EGD and Enbridge System.

FINANCING ACTIVITIES

In 2008, the Company generated $1,840.2 million through financing activities compared with $904.2 million and $268.1 million in 2007 and 2006, respectively.

Short-term borrowings at EGD are used primarily to finance working capital, including inventory.

In 2008, the Company added new credit facilities of $1.3 billion. Increased funding through commercial paper issuances and draws under committed credit facilities was required in 2008 to fund capital expenditures and the Company's investment in EEP. In 2007, the Company expanded its available liquidity through credit facility expansions and additions totaling $1.9 billion.

In the last quarter of 2008, the Company issued $0.5 billion of long-term notes. Specifically, EGD issued a $0.2 billion five-year term note and Enbridge Pipelines Inc. closed a $0.3 billion ten-year term note. The Company had total note maturities of $0.6 billion, of which $0.3 billion was repaid by EGD. Financing activities in 2007 included the issuance of US$1.1 billion of term notes in the U.S. market and

$0.2 billion of term notes in the Canadian market to offset term note maturities of $0.6 billion. During 2006, the Company issued $1.1 billion and repaid $400 million of term notes.

During 2008, the Company borrowed $0.3 billion and US$0.9 billion in project financing that is non-recourse to the Company, for the Canadian and U.S. components of the Southern Lights project. This financing resulted in the full repayment and cancellation of a US$0.5 billion facility established in 2007 to fund project costs directly related to the Southern Lights Project on an interim basis, which had been guaranteed by the Company.

Dividends paid on common shares decreased in 2008 due to the increased use of the Company's dividend reinvestment plan, which provided a $130.1 million increase in equity funding. Dividends paid on common shares increased in 2007 due to an increased number of common shares outstanding and a higher dividend rate.

Equity Issuance

On February 2, 2007, Enbridge closed the issuance to the public of 13.5 million common shares for $38.75 per share and issued 1.5 million common shares to Noverco for $38.75 per share, which maintained Noverco's ownership interest in Enbridge at approximately 9.5%. Net proceeds from both offerings totaled $566.4 million.

Preferred Securities

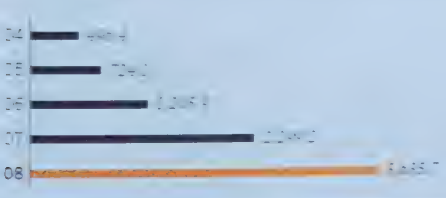
The Company redeemed its $200 million, 7.8% Preferred Securities on February 15, 2007.

EXPECTED CAPITAL EXPENDITURES

The numerous organic growth projects and other growth initiatives described in the business unit sections will require capital funding. The Company also requires capital for ongoing core maintenance and capital improvements in many of its businesses. In total, Enbridge expects to spend approximately $3.7 billion during 2009 on capital projects and maintenance. The Company expects to finance these expenditures through cash from operating activities and available liquidity. The Company may also raise capital through the monetization or disposition of selected assets.

The decision to finance with debt or equity is based on the capital structure for each business and the overall capitalization of the consolidated enterprise. Certain of the regulated pipeline and gas distribution businesses issue long-term debt to finance capital expenditures. For certain construction projects, financing costs are eligible for reimbursement through tolls. This external financing may be supplemented by debt or equity injections from the parent company. Debt, and equity when required, has been issued by the Company to finance business acquisitions, investments in subsidiaries and long-term investments.

Funds for debt retirements are generated through cash provided from operating activities as well as through the issue of replacement debt.



Capital Expenditures (millions of Canadian dollars)

Capital expenditures increased in 2008 primarily due to expenditures on growth in projects as well as core maintenance expenditures incurred.

Payments due for contractual obligations over the next five years and thereafter are as follows:

(millions of Canadian dollars)	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Long-term debt [1]	10,673.7	533.1	750.0	450.0	8,940.6
Non-recourse long-term debt [1]	1,617.2	176.2	259.7	218.3	963.0
Capital and operating leases	180.0	15.1	32.3	35.2	97.4
Long term contracts [2, 3]	3,345.4	2,058.8	616.4	407.5	262.7
Pension obligations [4]	48.4	48.4	–	–	–
Total Contractual Obligations	15,864.7	2,831.6	1,658.4	1,111.0	10,263.7

1 *Excludes interest. Changes to the planned funding requirements are dependent on the terms of any debt re-financing agreements.*

2 *Approximately $1,579.0 million of these contracts are commitments for materials related to the construction of Liquids Pipelines projects. Changes to the planned funding requirements, including cancelation, are dependent on changes to the related projects.*

3 *Contracts totaling $35 million are within proportionately consolidated joint venture entities and contracts totaling $230.3 million are between the Company and proportionately consolidated joint venture entities.*

4 *Assumes no discretionary payments will be made into the pension plans in 2009. Contributions subsequent to 2009 will be made in accordance with the independent actuarial valuations required as of December 31, 2009. Contributions, including discretionary payments, may be larger than current amounts pending future asset performance.*

SENSITIVITY ANALYSIS

The Company's earnings will fluctuate with changes in certain market prices, volumetric throughput on certain assets, with weather and other factors.

MARKET PRICES

Earnings at Risk (EaR) is the principal risk management metric used to quantify market price risk sensitivity at Enbridge. EaR is an objective, statistically derived risk metric that measures, with a 97.5% level of confidence, the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period. The Company's policy is to target a maximum EaR of 5% of 1 year forecasted earnings. On December 31, 2008, the Company's EaR was 2.5% (2007 – 2.8%) of 1 year forecasted adjusted earnings.

The following table shows the EaR from changes to different types of market price risk. These EaR numbers are based on business conditions and hedging programs as of December 31, 2008 and may not be applicable to other periods.

Risk	EaR
Commodity	$13.7 million
Foreign Exchange	$3.6 million
Interest Rate	$3.2 million

VOLUMETRIC THROUGHPUT

Transportation volumetric risks are managed through tariff agreements. Most of the Company's tariff agreements provide for take-or-pay or throughput insensitivity.

WEATHER

Weather is a significant driver of delivery volumes at EGD, given that a significant portion of EGD's customers use natural gas for space heating. Weather, measured in terms of degree day deficiency, normally directly impacts EGD's earnings as noted below. Degree-day is a measure of coldness, calculated as the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius.

Factor	Incremental change	Approximate incremental impact
Weather	17 degree days	1 billion cubic feet
Volume	1 billion cubic feet	$1.4 million (after-tax)

In recent years weather has impacted earnings by a larger magnitude than the above sensitivities would suggest. This results from the unusual pattern of distribution of degree days during the year and their relative effectiveness. Degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

Weather risk is also present in Enbridge Offshore Pipelines; hurricanes have impacted earnings by $11 million in 2008.

RISK MANAGEMENT

The Company's business activities are subject to execution, financing, market price, credit and operating risks, among others. The Company has formal risk management policies, processes and systems designed to mitigate these risks.

The current economic conditions have not caused the Company to change any risk management practices. The existing philosophy and framework was designed to be applied consistently in all market conditions. The Company continues to closely measure and monitor risks using best practice methodologies and manage exposures within the risk constraints of approved policies.

EXECUTION RISK

The Company's ability to successfully execute the development of its organic growth projects may be influenced by capital constraints, third-party opposition, delays in government approvals, cost escalations, construction delays and shortages (collectively Execution Risk). The Company's significant growth plans may strain its resources and may be subject to high cost pressures in the North American energy sector. Early stage project risks include right-of-way procurement, special interest group opposition, Crown consultation, environmental and regulatory permitting. Cost escalations may impact project economics. Construction delays due to slow delivery of materials, contractor non-performance, weather conditions and shortages may impact project development. Labour shortages, inexperience and productivity issues may also affect the successful completion of the projects.

The Company has a clearly defined management and governance structure for all major projects. Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements. The Company's emphasis on corporate social responsibility promotes generally positive relationships with landowners, aboriginal groups and governments. Cost tracking and centralized purchasing is used on all major projects. Strategic relationships have been developed with suppliers and contractors. Compensation programs, communications and the working environment are aligned to attract, develop and retain qualified personnel. In early 2008, the Company made changes in its senior management team structure which further emphasize successful project execution.

FINANCING RISK

The Company's financing risk relates to the price volatility and availability of debt and equity to finance organic growth projects and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian and U.S. debt and equity market conditions can change dramatically, affecting capital availability.

To address this risk, the Company maintains sufficient liquidity through committed credit facilities with its banking groups which would enable the Company to fund all anticipated requirements for one year without accessing the capital markets. In addition, the Company ensures that it can readily access the Canadian and U.S. public capital markets by maintaining current shelf prospectuses with the securities regulators.

MARKET PRICE RISK

Enbridge's earnings are subject to movements in interest rates, foreign exchange rates and commodity prices (collectively Market Price Risk). Given the Company's desire to maintain a stable and consistent earnings profile, it has implemented a Board of Directors approved Market Price Risk Policy to minimize the likelihood that adverse earnings fluctuations arising from movements in market prices across all of its

businesses will exceed a defined tolerance. The primary Market Price Risk metric used to monitor risk and establish limits within that policy is EaR, as described above under Sensitivity Analysis.

The Company uses derivative financial instruments for market price risk management purposes. The following summarizes the types of market price risks to which the Company is exposed and the financial derivative hedging programs implemented.

Foreign Exchange Risk

The Company has exposure to foreign currency exchange rates, primarily arising from its U.S. dollar denominated investments, where carrying values, cashflows and earnings are subject to foreign exchange rate variability. The Company has implemented a policy whereby it must hedge a minimum level of foreign currency denominated earnings exposures identified over the next five year period. Under this policy, the Company has substantially hedged this exposure. The Company may also hedge shorter term anticipated foreign currency denominated capital expenditures. The earnings exposure from the foreign exchange positions is managed within the overall consolidated EaR limits of the Company.

Interest Rate Risk

The Company's cashflows and earnings are exposed to interest rate fluctuations due to the regular repricing of its variable rate debt. Floating to fixed interest rate swaps, collars and forward rate agreements are used to hedge against the effect of future interest rate movements. The Company monitors its debt portfolio mix of fixed and variable rate debt instruments to ensure that the consolidated portfolio of debt stays within its Board of Directors approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding. The Company is also exposed to fluctuations in longer term interest rates ahead of anticipated fixed rate debt issuances. Many of the Company's existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls. The Company may enter into interest rate derivatives to hedge a portion of the interest cost of these future debt issues. The earnings exposure from the interest rate portfolio is managed within the overall consolidated EaR limits of the Company. As well, for certain construction projects, financing costs are eligible for reimbursement through tolls.

Information about the debt portfolio is included in Notes 15 and 16 of the 2008 Annual Consolidated Financial Statements.

Commodity Price Risk

The Company's cashflows and earnings are exposed to changes in commodity prices as a result of ownership interest in certain assets, as well as through the activities of its Energy Services affiliates. The Company uses natural gas, power, crude oil and NGL derivative instruments to fix a portion of the variable price exposures that may arise from commodity usage, storage, transportation and supply agreements. The earnings exposure from the commodity positions is managed within business unit EaR sub-limits, as well as within the overall consolidated EaR limits of the Company.

Fair Values of Derivative Instruments

Information about the financial instruments (including derivatives) outstanding at year end is included in Note 22 of the 2008 Annual Consolidated Financial Statements.

CREDIT RISK

Credit risk arises from trade receivables, which is mitigated by credit exposure limits, contractual and collateral requirements and netting arrangements. Credit risk in the Gas Distribution and Services segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. Certain large volume customers are exposed in times of economic uncertainty. In these cases, the Company has secured credit enhancement to assist in mitigating credit exposure.

Entering into derivative financial instruments can also give rise to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts

where the Company would incur a loss in replacing the instrument. Overall credit exposure limits have been set in the Board of Directors approved Credit Policy.

The Company minimizes credit risk by entering into risk management transactions only with institutions that possess solid investment grade credit ratings or have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty. During 2008, the Company rebalanced its exposure to certain financial counterparties through the discontinuance of certain hedges. For transactions with terms greater than five years, the Company may also require a counterparty that would otherwise meet the Company's credit criteria to provide collateral.

During 2008, notwithstanding the above mitigants, severe market conditions caused two counterparties to default resulting in the Company's first meaningful credit losses. These losses, included in Gas Distribution and Services earnings, totaled $5.7 million.

OPERATING RISKS

Pipeline Operating Risk

Pipeline leaks are an inherent risk of operations. Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the pipeline systems. The occurrence or continuance of any of these events could increase the cost of operating the Company's pipelines or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage system integrity, which includes the development and use of in-line inspection tools. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks.

Regulation

Many of the Company's pipeline operations are regulated and are subject to regulatory risk. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States has changed significantly in past years and there is no assurance that further substantial changes will not occur. These changes may adversely affect toll structures or other aspects of pipeline operations or the operations of shippers.

Environmental, Health and Safety Risk

The Company's operations, facilities and petroleum product shipments are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. The Company's facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and pipelines must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing greenhouse

gas emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. Restrictions on other resources, such as water or electricity, may affect the Company's upstream customers' ability to produce. The Company could be targeted, along with the oil sands industry, by environmental groups attempting to draw attention to greenhouse gas emissions.

Enbridge is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment benefits everyone and delivers increased value to shareholders, customers and employees. Enbridge has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Regular reviews and audits are conducted to assess compliance with legislation and Company policy.

Special Interest Groups

The Company is exposed to the risk of higher costs, delays or even project cancellations due to increasing pressure on government and regulators by aboriginal groups, landowners and other special interest groups. Recent Supreme Court decisions have increased the ability of special interest groups to make claims and oppose projects in regulatory and legal forums. The Company works proactively with special interest groups to identify and develop an appropriate response to concerns regarding its projects. The Company's CSR program also reports on the Company's responsiveness to environmental and community issues. Please see the annual CSR report for further details regarding the CSR program.

Aboriginal Relations

Canadian judicial decisions have recognized that Aboriginal rights and treaty rights exist in proximity to the Company's operations and future project developments. The courts have also confirmed that the Crown has a duty to consult with Aboriginal peoples when its decisions or actions may adversely affect Aboriginal rights and interests or treaty rights [1]. While good business practice generally, and a Crown duty in some cases, consultation has the potential to delay regulatory approval processes and construction, which may affect project economics.

Given this environment and the breadth of relationships across the Company's geographic span, Enbridge has recently reviewed and updated its Indigenous Peoples Policy, which has been renamed the Aboriginal and Native American Policy. The new Policy promotes the achievement of participative and mutually beneficial relationships with Aboriginal and Native American groups affected by the Company's projects and operations. Specifically, the Policy sets out principles governing the Company's relationships with Aboriginal and Native American peoples and makes commitments to work with Aboriginal peoples and Native Americans so they may realize sustainable benefits from our projects and operations. Notwithstanding the Company's efforts to this end, the issues are complex and the impact of Aboriginal relations on Enbridge's operations and development initiatives is uncertain.

Workforce Development

A lack of qualified and properly trained technical, professional and operational staff and leaders would increase the risk that the Company will not be able to implement its corporate strategy. This risk may be compounded by the increasing rates of retirement due to workforce demographics, turnover due to competition in certain markets and growing demand for staff to support business growth. The Company continues to monitor company-wide workforce planning and is focused on recruiting efforts while enhancing employee engagement. The Company offers competitive compensation programs, training, leadership development and succession planning. Further, the supply of human capital is balanced between hiring full-time employees and expanding the contractor workforce, particularly in the Major Projects' department.

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1 See generally, *R. v. Sparrow*, [1990] 1 S.C.R. 1075, *R. v. Badger*, [1996] 1 S.C.R. 771 and *Delgamuukw v. B.C.*, [1997] 3 S.C.R. 1010.

Terrorism

The risk of terrorism appears to be growing based on the high profile of the petroleum industry in Canada and the reliance of the U.S. on Canadian exports. An act of terrorism may result in the loss of upstream supplies, pipelines, distribution or storage controls systems with safety and environmental implications. The Company manages this risk through its Human Resources Protection Program, Crisis Management Plan and insurance programs where available.

CRITICAL ACCOUNTING ESTIMATES

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2008 of $16,389.6 million, or 66% of total assets, is generally provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service. When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of the Company's assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Company's pipelines as well as the demand for crude oil and natural gas and the integrity of the Company's systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Company's business segments, except the Corporate segment. For certain rate regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates. Reflecting the resource resiliency of the basins the Company serves, revised assumptions have typically resulted in extending useful lives.

REGULATORY ASSETS AND LIABILITIES

Certain of the Company's Liquids Pipelines, Gas Pipelines and Gas Distribution and Services businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the ERCB and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking, and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under generally accepted accounting principles for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the regulator. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the income statement captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2008, the Company's regulatory assets totaled $625.5 million (2007 – $548.4 million) and regulatory liabilities totaled $102.6 million (2007 – $173.7 million). To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and other post-employment benefits (OPEB) other than pensions to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method. This method involves complex actuarial calculations using several assumptions including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense

recognized and the recorded obligation in future periods. The decline in the capital markets has reduced the current market value of the plan assets; however, the discount rate has increased resulting in a lower expected benefit obligation substantially offsetting the decline in the plan assets. The Company remains able to pay the current benefit obligations using cash from operations. See Note 25 to the 2008 Annual Consolidated Financial Statements for disclosure of the difference between the actual and the expected results for the past two years. Pension expense is recorded within all of the Company's business segments with the exception of EGD which records pension expense on a cash basis in accordance with rate regulated accounting.

Assuming no discretionary funding is made into the pension plans, funding in 2009 will be approximately $48 million which is not considered significant to the Company.

	Pension Benefits		OPEB	
Impact of a 0.5% Change in Key Assumptions	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	74.6	9.7	12.9	1.3
Decrease in expected return on assets	n/a	6.1	n/a	0.2
Decrease in rate of salary increase	(19.2)	(4.8)	–	–

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments, including Enbridge Gas Distribution Inc. and Enbridge Energy Company, Inc., are disclosed in Note 29 of the 2008 Annual Consolidated Financial Statements.

ASSET RETIREMENT OBLIGATIONS

The fair value of asset retirement obligations (AROs) associated with the retirement of long-lived assets are recognized as long-term liabilities in the period when they can be reasonably determined. The fair value approximates the cost a third party would charge in performing the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The present value of expected future cash flows is determined using assumptions such as the probability of abandonment in place versus removal and the estimated costs required upon abandonment in each case, the discount rate and the estimated time to abandonment. For the majority of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing, the long-lived nature of the assets and the scope of the asset retirements. Changes in any of these assumptions could materially affect the asset and liability recognized in respect of asset retirement obligations as well as the resulting accretion of the liability and depreciation of the asset within any of the Company's business segments.

CHANGE IN ACCOUNTING POLICIES

Information about the Company's changes in accounting policies is included in Note 2 of the 2008 Annual Consolidated Financial Statements.

FUTURE ACCOUNTING POLICIES

INTERNATIONAL FINANCIAL REPORTING STANDARDS

The Canadian Accounting Standards Board confirmed in February 2008 that publicly accountable entities will be required to adopt International Financial Reporting Standards (IFRS) for interim and

annual financial statements on January 1, 2011. The Company, as an SEC Registrant, has the option to use U.S. GAAP instead of IFRS. During the fourth quarter 2008, the Company chose IFRS since it believes that IFRS will provide a more transparent and appropriate presentation of financial results, and it would avoid the cost of a second conversion when the United States converges with IFRS in or about 2014 as planned.

Enbridge has established an IFRS governance structure to monitor the progress of the transition. This group is comprised of senior management from finance, treasury, tax and the Company's business units among others. The Audit, Finance and Risk Committee of the Board of Directors receives regular reports on the advancement of the IFRS transition plan. In addition, the Company has trained internal IFRS team members and has hired a public accounting firm to assist with project management and technical accounting advice, as needed.

The Company has a multiyear transition plan which includes four phases – diagnostic, project planning, policy design and implementation. In 2008, the Company completed the diagnostic phase and has identified the relevant differences between Canadian GAAP and IFRS. The Company is in the policy design stage and is also assessing the impact of policy alternatives on its financial statements, systems, processes and controls. As the transition progresses, the Company will provide increased clarity into the anticipated consequences of accounting policy changes. The Company is in the process of developing a detailed project plan for 2009 and 2010 which will include staff communications, a training plan and an external stakeholders communication plan. Policy design will be completed in 2009 and implementation will begin during 2009 and be completed by the end of 2010.

Changes in accounting policies and processes and collection of additional information for disclosure will require modifications to the Company's information technology systems and processes as well as its system of internal controls. The identified information technology system alterations are being incorporated into the detailed project plan to allow time to modify and test the systems before implementation during 2010. The impact on internal controls over financial reporting and disclosure controls and procedures will be determined during the policy design and implementation phases.

CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S securities law. As of the year ended December 31, 2008, an evaluation was carried out under the supervision of and with the participation of Enbridge's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of Enbridge's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by Enbridge in reports that it files with or submits to the Securities and Exchange Commission is recorded, processed, summarized and reported within the time periods required.

Management's Report on Internal Controls over Financial Reporting

Management of Enbridge Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the United States Securities and Exchange Commission and the Canadian Securities Administrators. The Company's internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with GAAP.

The Company's internal control over financial reporting includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

The Company's internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2008, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2008.

During the year ended December 31, 2008, there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

QUARTERLY FINANCIAL INFORMATION [1]

2008	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	**3,967.8**	**3,871.5**	**4,368.5**	**3,923.5**	**16,131.3**
Earnings applicable to common shareholders	**251.3**	**657.7**	**148.4**	**263.4**	**1,320.8**
Earnings per common share	**0.70**	**1.83**	**0.41**	**0.72**	**3.67**
Diluted earnings per common share	**0.70**	**1.81**	**0.41**	**0.71**	**3.64**
Dividends per common share	**0.33**	**0.33**	**0.33**	**0.33**	**1.32**

2007	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	3,358.2	2,728.7	2,634.0	3,198.5	11,919.4
Earnings applicable to common shareholders	227.0	146.5	78.1	248.6	700.2
Earnings per common share	0.65	0.41	0.22	0.70	1.97
Diluted earnings per common share	0.64	0.41	0.22	0.69	1.95
Dividends per common share	0.3075	0.3075	0.3075	0.3075	1.23

1 *Quarterly Financial Information has been extracted from financial statements prepared in accordance with generally accepted accounting principles.*

Revenue includes amounts billed to customers of EGD for natural gas, which varies with fluctuations in the commodity price. Higher natural gas commodity prices increase revenues, but would not similarly impact earnings, given the cost of natural gas flows through to customers. Fluctuations in commodity prices impact revenues and earnings from Energy Services businesses.

Significant items that impacted the quarterly earnings and revenue were as follows:

- Fourth quarter earnings in 2008 included higher contributions from Aux Sable and Energy Services, Liquids Pipelines and EGD. EGD's fixed charge per customer increased with a corresponding decrease in the per unit volumetric charge. These changes modify the quarterly earnings profile, but do not materially affect full year earnings as revenues are shifted from the colder winter quarters to the warmer summer quarters.

- Third quarter earnings in 2008 reflected increased earnings from Athabasca System, EGD, Aux Sable and Energy Services. Revenues increased due to higher average commodity prices in 2008.
- Second quarter 2008 earnings included a gain on the sale of the Company's investment in CLH as well as increased earnings from EEP, Aux Sable and Energy Services. Revenues were higher than the comparable 2007 period due to higher commodity prices impacting Energy Services.
- First quarter 2008 earnings included higher contributions from EGD as well as improved results in Aux Sable and Energy Services, partially offset by the recognition of an income tax charge related to previously owned U.S. pipeline assets. Revenues were higher than the comparable 2007 period due to higher commodity prices impacting Energy Services.
- Fourth quarter earnings in 2007 included the impact of tax changes, which increased consolidated earnings.
- Third quarter 2007 included a loss from Aux Sable.
- Second quarter 2007 included higher earnings from EGD due to colder than normal weather and a dilution gain in EEP.
- First quarter 2007 included higher earnings from EGD due to colder weather than the prior year period and the receipt of 2005 hurricane insurance proceeds.

FOURTH QUARTER 2008 HIGHLIGHTS

Earnings applicable to common shareholders were $263.4 million, or $0.72 per share, for the three months ended December 31, 2008, compared with $248.6 million, or $0.70 per share, for the three months ended December 31, 2007. Significant factors that increased earnings included unrealized fair value gains on derivative financial instruments in Aux Sable and Energy Services, AEDC in Liquids Pipelines and a higher contribution from EGD, partially offset by decreased earnings from International as the Company sold its interest in CLH in the second quarter of 2008.

SELECTED ANNUAL INFORMATION

(millions of Canadian dollars, except per share amounts)	**2008**	2007	2006
Total Revenues	**16,131.3**	11,919.4	10,644.5
Common Share Dividends	**489.3**	452.3	403.1
Total Assets	**24,701.4**	19,907.4	18,379.3
Total Long-Term Liabilities	**13,976.1**	11,117.4	10,544.8
Earnings per Common Share	**3.67**	1.97	1.81
Diluted Earnings per Common Share	**3.64**	1.95	1.79
Dividends Per Common Share	**1.32**	1.23	1.15

Total assets and long-term liabilities increased primarily because of investments in organic growth projects.

NON-GAAP RECONCILIATIONS

(millions of Canadian dollars)	**2008**	2007	2006
GAAP earnings as reported	**1,320.8**	700.2	615.4
Significant after-tax non-operating factors and variances:			
Liquids Pipelines			
Enbridge System – impact of tax changes	**–**	(1.2)	–
Feeder Pipelines and Other – asset impairment loss	**4.1**	–	–
Gas Pipelines			
Alliance Pipeline US – shipper claim settlement	**(2.8)**	–	–
Offshore – property insurance recovery from 2005 hurricanes, net of repair costs	**–**	(5.3)	–
Sponsored Investments			
EEP – dilution gain on Class A unit issuance	**(4.5)**	(11.8)	–
EEP – unrealized derivative fair value (gains)/losses	**(7.2)**	6.3	(6.5)
EEP – gain on sale of Kansas Pipeline Company	**–**	(3.0)	–
EEP – impact of 2008 hurricanes and project write-offs	**2.2**	–	–
EIF – Alliance Canada shipper claim settlement	**(1.3)**	–	–
EIF – impact of tax changes	**–**	(1.9)	(6.0)
Gas Distribution and Services			
EGD – colder/(warmer) than normal weather	**(23.1)**	(14.2)	36.9
EGD – provision for one-time charges	**2.8**	–	–
EGD/Noverco – impact of tax changes	**–**	(26.8)	(28.9)
Noverco – dilution gains	**–**	–	(4.0)
Energy Services – unrealized derivative fair value (gains)/losses	**(22.6)**	2.4	–
Energy Services – SemGroup and Lehman bankruptcies	**5.7**	–	–
Aux Sable – unrealized derivative fair value (gains)/losses	**(54.5)**	28.1	–
Other – gain on sale of investment in Inuvik Gas	**(4.6)**	–	–
International			
CLH – gain on sale of investment	**(556.1)**	–	–
CLH – gain on land sale	**–**	(5.2)	–
Corporate			
Gain on sale of corporate aircraft	**(4.9)**	–	–
U.S. pipeline tax decision	**32.2**	–	–
Unrealized derivative fair value gains	**(26.2)**	–	–
Asset impairment loss	**17.3**	–	–
Impact of tax changes	**–**	(31.1)	(14.0)
Adjusted earnings	**677.3**	636.5	592.9

OUTSTANDING SHARE DATA

	Number
Preferred Shares, Series A (non-voting equity shares)	5,000,000
Common shares – issued and outstanding (voting equity shares)	373,032,095
Total issued and outstanding stock options (7,535,744 vested)	14,364,183

Outstanding share data information is provided as at February 4, 2009.

RELATED PARTY TRANSACTIONS

Information about the Company's related party transactions is included in Note 28 of the 2008 Annual Consolidated Financial Statements.

Additional information relating to Enbridge, including the Annual Information Form, is available on www.sedar.com.

Dated February 19, 2009

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE INC.

Financial Reporting

Management is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit, Finance & Risk Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2008, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2008.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

Patrick D. Daniel
President & Chief Executive Officer

J. Richard Bird
Executive Vice President &
Chief Financial Officer

February 12, 2009

INDEPENDENT AUDITORS' REPORT

TO THE SHAREHOLDERS OF ENBRIDGE INC.

We have completed integrated audits of Enbridge Inc.'s 2008, 2007 and 2006 consolidated financial statements and of its internal control over financial reporting as at December 31, 2008. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of Enbridge Inc. as at December 31, 2008 and December 31, 2007, and the related consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the years in the three year period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Company's financial statements as at December 31, 2008 and December 31, 2007 and for each of the years in the three year period ended December 31, 2008 in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and December 31, 2007, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

Internal Control over Financial Reporting

We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2008, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2008 based on criteria established in Internal Control – Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

February 12, 2009

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	2008	2007	2006
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**13,431.9**	9,536.4	8,264.5
Transportation and other services	**2,699.4**	2,383.0	2,380.0
	16,131.3	11,919.4	10,644.5
Expenses			
Commodity costs	**12,792.0**	9,009.5	7,824.6
Operating and administrative	**1,312.2**	1,163.7	1,084.2
Depreciation and amortization	**658.4**	596.9	587.4
	14,762.6	10,770.1	9,496.2
	1,368.7	1,149.3	1,148.3
Income from Equity Investments	**177.1**	167.8	180.3
Other Investment Income *(Note 26)*	**202.7**	195.1	107.8
Interest Expense *(Note 15)*	**(550.8)**	(550.0)	(567.1)
Gain on Sale of Investment in CLH *(Note 5)*	**694.6**	–	–
	1,892.3	962.2	869.3
Non-Controlling Interests	**(55.7)**	(45.9)	(54.7)
	1,836.6	916.3	814.6
Income Taxes *(Note 24)*	**(508.9)**	(209.2)	(192.3)
Earnings	**1,327.7**	707.1	622.3
Preferred Share Dividends	**(6.9)**	(6.9)	(6.9)
Earnings Applicable to Common Shareholders	**1,320.8**	700.2	615.4
Earnings per Common Share *(Note 18)*	**3.67**	1.97	1.81
Diluted Earnings per Common Share *(Note 18)*	**3.64**	1.95	1.79

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	2008	2007	2006
(millions of Canadian dollars)			
Earnings	**1,327.7**	707.1	622.3
Other Comprehensive Income/(Loss)			
Change in unrealized gains/(losses) on cash flow hedges, net of tax	**(127.4)**	96.4	–
Reclassification to earnings of realized cash flow hedges, net of tax	**(1.3)**	(6.7)	–
Other comprehensive gain/(loss) from equity investees	**49.2**	(19.8)	–
Non-controlling interest in other comprehensive income	**(19.6)**	4.9	–
Change in foreign currency translation adjustment	**576.8**	(447.1)	87.6
Change in unrealized gains/(losses) on net investment hedges, net of tax	**(159.9)**	174.9	(51.6)
Other Comprehensive Income/(Loss)	**317.8**	(197.4)	36.0
Comprehensive Income *(Note 2)*	**1,645.5**	509.7	658.3

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2008**	2007	2006
(millions of Canadian dollars, except per share amounts)			
Preferred Shares *(Note 18)*	**125.0**	125.0	125.0
Common Shares *(Note 18)*			
Balance at beginning of year	**3,026.5**	2,416.1	2,343.8
Common shares issued	**–**	566.4	–
Dividend reinvestment and share purchase plan	**131.3**	17.7	18.4
Shares issued on exercise of stock options	**36.2**	26.3	53.9
Balance at End of Year	**3,194.0**	3,026.5	2,416.1
Contributed Surplus			
Balance at beginning of year	**25.7**	18.3	10.0
Stock-based compensation	**14.5**	8.9	10.5
Options exercised	**(2.3)**	(1.5)	(2.2)
Balance at End of Year	**37.9**	25.7	18.3
Retained Earnings			
Balance at beginning of year	**2,537.3**	2,322.7	2,098.2
Earnings applicable to common shareholders	**1,320.8**	700.2	615.4
Common share dividends	**(489.3)**	(452.3)	(403.1)
Dividends paid to reciprocal shareholder	**14.6**	13.7	12.2
Cumulative impact of change in accounting policy *(Note 2)*	**–**	(47.0)	–
Balance at End of Year	**3,383.4**	2,537.3	2,322.7
Accumulated Other Comprehensive Income/(Loss) *(Note 20)*			
Balance at beginning of year	**(285.0)**	(135.8)	(171.8)
Other comprehensive income/(loss)	**317.8**	(197.4)	36.0
Cumulative impact of change in accounting policy *(Note 2)*	**–**	48.2	–
Balance at End of Year	**32.8**	(285.0)	(135.8)
Reciprocal Shareholding *(Note 10)*			
Balance at beginning of year	**(154.3)**	(135.7)	(135.7)
Participation in common shares issued	**–**	(18.6)	–
Balance at End of Year	**(154.3)**	(154.3)	(135.7)
Total Shareholders' Equity	**6,618.8**	5,275.2	4,610.6
Dividends Paid per Common Share	**1.32**	1.23	1.15

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	2008	2007	2006
(millions of Canadian dollars)			
Operating Activities			
Earnings	**1,327.7**	707.1	622.3
Depreciation and amortization	**658.5**	596.9	587.4
Unrealized (gains)/losses on derivative instruments	**(120.3)**	32.3	–
Equity earnings in excess of cash distributions	**(81.6)**	(35.2)	(54.2)
Gain on reduction of ownership interest	**(12.3)**	(33.9)	–
Gain on sale of investment in CLH	**(694.6)**	–	–
Gain on sale of investment in Inuvik Gas	**(5.7)**	–	–
Future income taxes	**258.1**	40.8	(21.0)
Goodwill and asset impairment losses	**22.7**	–	–
Allowance for equity funds used during construction	**(58.9)**	(15.1)	(1.5)
Non-controlling interests	**55.7**	45.9	54.7
Other	**48.7**	19.2	3.9
Changes in operating assets and liabilities *(Note 27)*	**(10.3)**	(6.4)	123.7
	1,387.7	1,351.6	1,315.3
Investing Activities			
Acquisitions *(Note 5)*	–	–	(101.4)
Long-term investments	**(659.3)**	(20.3)	(362.3)
Sale of investment in CLH	**1,369.0**	–	–
Sale of investment in Inuvik Gas	**13.5**	–	–
Settlement of CLH hedges	**(47.0)**	–	–
Additions to property, plant and equipment	**(3,635.7)**	(2,299.2)	(1,205.9)
Affiliate loans, net	–	15.6	28.0
Change in construction payable	**106.6**	75.1	44.0
	(2,852.9)	(2,228.8)	(1,597.6)
Financing Activities			
Net change in short-term borrowings	**329.0**	(262.3)	(266.9)
Net change in commercial paper and credit facility draws	**750.8**	336.8	188.2
Net change in non-recourse short-term debt	**31.6**	43.1	57.7
Debenture and term note issues	**497.8**	1,342.2	1,125.0
Debenture and term note repayments	**(602.0)**	(634.5)	(400.0)
Net change in Southern Lights project financing	**1,238.3**	–	–
Non-recourse long-term debt issues	**6.4**	14.4	2.8
Non-recourse long-term debt repayments	**(65.1)**	(58.8)	(60.5)
Distributions to non-controlling interests	**(9.9)**	(18.2)	(31.3)
Common shares issued	**29.4**	583.8	63.1
Preferred share dividends	**(6.9)**	(6.9)	(6.9)
Common share dividends	**(359.2)**	(435.4)	(403.1)
	1,840.2	904.2	268.1
Increase/(Decrease) in Cash and Cash Equivalents	**375.0**	27.0	(14.2)
Cash and Cash Equivalents at Beginning of Year	**166.7**	139.7	153.9
Cash and Cash Equivalents at End of Year [1]	**541.7**	166.7	139.7

The accompanying notes are an integral part of these consolidated financial statements.

1 *Cash and cash equivalents consists of $67.5 million (2007 – $78.9 million; 2006 – $72.9 million) of cash and $474.2 million (2007 – $87.8 million; 2006 – $66.8 million) of short-term investments.*

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31, *(millions of Canadian dollars)*	**2008**	2007
Assets		
Current Assets		
Cash and cash equivalents	**541.7**	166.7
Accounts receivable and other *(Note 6)*	**2,322.5**	2,388.7
Inventory *(Note 7)*	**844.7**	709.4
	3,708.9	3,264.8
Property, Plant and Equipment, net *(Note 8)*	**16,389.6**	12,597.6
Long-Term Investments *(Note 10)*	**2,491.8**	2,076.3
Deferred Amounts and Other Assets *(Note 11)*	**1,318.4**	1,182.0
Intangible Assets *(Note 12)*	**225.3**	212.0
Goodwill *(Note 13)*	**389.2**	388.0
Future Income Taxes *(Note 24)*	**178.2**	186.7
	24,701.4	19,907.4
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-term borrowings *(Note 15)*	**874.6**	545.6
Accounts payable and other *(Note 14)*	**2,411.5**	2,213.8
Interest payable	**101.9**	89.1
Current maturities of long-term debt *(Note 15)*	**533.8**	605.2
Current maturities of non-recourse long-term debt *(Note 16)*	**184.7**	61.1
	4,106.5	3,514.8
Long-Term Debt *(Note 15)*	**10,154.9**	7,729.0
Non-Recourse Long-Term Debt *(Note 16)*	**1,474.0**	1,508.4
Other Long-Term Liabilities	**259.0**	253.9
Future Income Taxes *(Note 24)*	**1,290.8**	975.6
Non-Controlling Interests *(Note 17)*	**797.4**	650.5
	18,082.6	14,632.2
Shareholders' Equity		
Share capital		
Preferred shares *(Note 18)*	**125.0**	125.0
Common shares *(Note 18)*	**3,194.0**	3,026.5
Contributed surplus	**37.9**	25.7
Retained earnings	**3,383.4**	2,537.3
Accumulated other comprehensive income/(loss) *(Note 20)*	**32.8**	(285.0)
Reciprocal shareholding *(Note 10)*	**(154.3)**	(154.3)
	6,618.8	5,275.2
Commitments and Contingencies *(Note 29)*	**24,701.4**	19,907.4

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

David A. Arledge
Chair

David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five operating segments identified based on products and services offered: Liquids Pipelines, Gas Pipelines, Sponsored Investments, Gas Distribution and Services and International. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES

Liquids Pipelines includes the Canadian common carrier pipeline and feeder pipelines that transport crude oil and other liquid hydrocarbons including the Enbridge System, the Athabasca System, Spearhead Pipeline, Southern Lights Pipeline and a proportionately consolidated investment in the Olympic Pipeline.

GAS PIPELINES

Gas Pipelines consists of proportionately consolidated investments in natural gas pipelines including the U.S. portion of the Alliance Pipeline, Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico.

SPONSORED INVESTMENTS

Sponsored Investments consists of the Company's investments in Enbridge Energy Partners, L.P. (EEP), a publicly traded master limited partnership, and Enbridge Energy Management, L.L.C. (EEM) (collectively, the Partnership) as well as Enbridge Income Fund (EIF).

The Partnership transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and natural gas liquids. EIF is a publicly traded income fund whose primary operations include a 50% interest in the Canadian portion of the Alliance Pipeline and a crude oil and liquids pipeline and gathering system.

GAS DISTRIBUTION AND SERVICES

Gas Distribution and Services consists of natural gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, and the Company's proportionately consolidated investment in Aux Sable, a natural gas fractionation and extraction business.

The Company's commodity marketing businesses are also included in Gas Distribution and Services. These businesses manage the Company's volume commitments on Alliance and Vector Pipelines as well as offer commodity storage, transport and supply management services.

INTERNATIONAL

The Company's International business consists of investments in two energy-delivery businesses, Oleoducto Central S.A. (OCENSA) in Colombia and, prior to its sale in June 2008, Compañía Logística de Hidrocarburos CLH, S.A. (CLH) in Spain.

CORPORATE

Corporate consists of new business development activities and investing and financing activities, including general corporate investments and financing costs not allocated to the business segments.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's financial statements are described in Note 32. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the financial statements. The most significant assets and liabilities where we must make estimates include: values of regulatory assets and liabilities *(Note 4)*; depreciation rates of property, plant and equipment *(Note 8)*; amortization rates of intangible assets *(Note 12)*; measurement of goodwill *(Note 13)*; valuation of

share based compensation *(Note 19)*; fair values of financial instruments *(Note 21 and Note 22)*; income taxes *(Note 24)*; post employment benefits *(Note 25)* and commitments and contingencies *(Note 29)*. Actual results could differ from these estimates.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of Enbridge Inc., its subsidiaries and its proportionate share of the accounts of joint ventures. EIF is consolidated in the accounts of the Company because it is a variable interest entity. The Company is the primary beneficiary of EIF through a combination of a 41.9% equity interest and a preferred unit investment. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for according to their classification as held to maturity, loans and receivables or available for sale (see Financial Instruments). All long-term investments are assessed for impairment if the Company identifies an event indicative of possible impairment.

REGULATION

Certain of the Company's Liquids Pipelines, Gas Pipelines and Gas Distribution and Services businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Energy Resources Conservation Board in Alberta (ERCB), the New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. In the absence of rate regulation, the Company would not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded in Deferred Amounts and Other Assets and current regulatory assets are recorded in Accounts Receivable and Other. Long-term regulatory liabilities are included in Other Long-Term Liabilities and current regulatory liabilities are recorded in Accounts Payable and Other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment *(Note 4)*.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component. In the absence of rate regulation, the Company would capitalize only the interest component; therefore, the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

With the approval of the regulator, Enbridge Gas Distribution (EGD) capitalizes a percentage of certain operating costs. EGD is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such costs may be charged to current earnings.

Contributions made to the defined benefit pension plan and the cost of providing post-employment benefits other than pensions (OPEB) for the regulated operations of Gas Distribution and Services are expensed as paid, consistent with the recovery of such costs in rates. Canadian GAAP requires costs and obligations for defined benefit pension plans and OPEB to be determined using the projected benefit method and charged to earnings as services are rendered.

REVENUE RECOGNITION

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed. Customer credit worthiness is assessed before agreements are signed.

For the rate-regulated portion of the Company's main Canadian crude oil pipeline system, revenue is recognized in a manner that is consistent with the underlying agreements as approved by the regulator. Certain Liquids Pipelines revenues are recognized under the terms of a committed 30-year delivery contract rather than the cash tolls received.

For rate-regulated operations in Gas Pipelines and Sponsored Investments, transportation revenues include amounts related to expenses recognized in the financial statements that are expected to be recovered from shippers in future tolls. Revenue is recognized in a given period for tolls received to the extent that expenses are incurred. Differences between the recorded transportation revenue and actual toll receipts give rise to receivable or payable balances.

A significant portion of Gas Distribution and Services operations are subject to rate-regulation. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the regulator. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. For the non-regulated portion of Gas Distribution and Services operations, delivery or service performance only takes place when there is a sales contract in place specifying delivery volumes or services required and sales prices.

FINANCIAL INSTRUMENTS

The Company classifies financial assets as either held for trading, held to maturity, loans and receivables or available for sale. The Company classifies financial liabilities as either held for trading or other financial liabilities.

Financial assets and liabilities that are "held for trading" are measured at fair value with changes in fair value recognized in earnings in other investment income, except for derivatives that are designated as, and determined to be, effective hedging instruments, whose changes in fair value are recorded in Other Comprehensive Income (OCI).

Generally, the Company classifies equity investments in other entities that are not accounted for under the equity method or joint venture accounting as "available for sale". Financial assets that are available for sale are measured at fair value, with changes in those fair values recorded in OCI. Where actively quoted prices are not available for fair value measurement, these financial assets are measured at amortized cost. Dividends received from available for sale financial assets are recognized when the right to receive payment is established.

The Company assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired. For investments classified as "available for sale", where no actively quoted market exists for the security, the Company internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the investment.

Financial assets that are "held to maturity" and "loans and receivables" and financial liabilities that are "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Cash and cash equivalents are designated as "held for trading" and are measured at carrying value which approximates fair value due to the short-term nature of these instruments. Accounts receivable and other are designated as "loans and receivables". Short-term borrowings, accounts payable and other, interest payable, long-term debt and non-recourse long-term debt are designated as "other financial liabilities".

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

Hedges

The Company uses derivatives and non-derivative financial instruments to manage changes in commodity prices, foreign currency exchange rates and interest rates. Hedge accounting is optional and it requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction.

Cash Flow Hedges

The Company uses cash flow hedges to manage changes in commodity prices, foreign currency exchange rates and interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in OCI and reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset or liability. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period they occur.

Fair Value Hedges

The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability ceases to be remeasured at fair value and the fair value adjustment is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges

The Company uses net investment hedges to manage the carrying values of U.S. dollar denominated foreign investments. The effective portion of the change in the fair value of the hedging instrument is recorded in OCI. Any ineffectiveness is recorded in current period earnings. Amounts recorded in Accumulated Other Comprehensive Income or Loss (AOCI) are recognized in earnings when there is a reduction of the hedged net investment resulting from a sale of ownership interests.

Non-Hedge Derivatives

If a derivative instrument is not an effective hedge for accounting purposes or is not designated as hedging item, changes in the fair value are recorded in current period earnings.

INCOME TAXES

For non-regulated operations, the liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

The regulated activities of the Company recover income tax expense based on the taxes payable method when prescribed by regulators or in ratemaking agreements that are subject to regulatory approval. As a result, rates do not include the recovery of future income taxes related to temporary differences and the Company does not record future income tax assets or liabilities related to these differences. The Company expects that all unrecorded future income taxes will be recovered in rates when they become payable.

FOREIGN CURRENCY TRANSLATION

The Company's U.S. dollar operations are primarily self-sustaining. Self-sustaining operations are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates, with revenues and expenses translated using monthly average rates. Gains and losses arising on translation of these operations are included in the cumulative translation adjustment component of AOCI.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Gains or losses on foreign exchange are recorded in the Consolidated Statements of Earnings.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term deposits with a term to maturity of three months or less when purchased.

INVENTORY

Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded at the quarterly prices approved by the OEB in the determination of customer sales rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred for future refund or collection as approved by the OEB. Other inventory, consisting primarily of commodities held in storage, is recorded at the lower of cost and net realizable value.

PROPERTY, PLANT AND EQUIPMENT

Expenditures for construction, expansion, major renewals and betterments are capitalized; maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit. The Company capitalizes interest incurred during construction. For rate-regulated assets, if approved, an allowance for equity funds used during construction (AEDC) is capitalized at rates authorized by the regulatory authorities. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service.

IMPAIRMENT OF LONG-LIVED ASSETS

The Company reviews the carrying values of its long-lived assets at least annually or as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the fair value and that the decline is other than temporary based on future cash flows, the assets are written down to fair value.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, contractual receivables under the terms of long-term delivery contracts, derivative financial instruments as well as pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

INTANGIBLE ASSETS

Intangible assets consist primarily of acquired long-term transportation contracts which are amortized on a straight-line basis over the expected lives of the contracts.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. Goodwill is not subject to amortization but is tested for impairment at least annually. For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. Potential impairment is identified when the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value. Goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill, based on the fair value of the assets and liabilities of the reporting unit.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (AROs) associated with the retirement of long-lived assets are measured at fair value and recognized as Other Long-Term Liabilities in the period when they can be reasonably determined. The fair value approximates the cost a third party would charge in performing the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For certain of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

Depreciation expense for Gas Distribution and Services operations includes a provision for AROs at rates approved by the regulator. Actual costs incurred are charged to accumulated depreciation in accordance with regulatory treatment.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits. Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit

method and are charged to earnings as services are rendered, except for the regulated operations of Gas Distribution and Services, where contributions made to the plan are expensed as paid consistent with the recovery of such costs in rates. For defined contribution plans, contributions made by the Company are expensed.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values. Adjustments arising from plan amendments and the transitional amounts recognized on adoption of the accounting standard are amortized on a straight-line basis over the average remaining service period of the employees active at the date of amendment or transition. The excess of the net actuarial gain or loss over 10% of the greater of the benefit obligation and the fair value of plan assets is amortized over the average remaining service period of the active employees.

The Company also provides post-employment benefits other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years employees render service, except for the regulated operations of Gas Distribution and Services where the cost of providing these benefits is expensed as paid, consistent with the recovery of such costs in rates.

STOCK-BASED COMPENSATION

Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at fair value at the grant date and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility with a corresponding credit to contributed surplus. Balances in contributed surplus are transferred to share capital when the options are exercised.

Performance Stock Units (PSUs) vest at the completion of a three-year term and Restricted Stock Units vest at the completion of a 35-month term; both are settled in cash. During the term, an expense is recorded based on the number of units outstanding and the current market price of the Company's shares with an offset to Other Long-Term Liabilities. The value of the PSU's is also dependent on the Company's performance relative to performance targets set out under the plan.

COMPARATIVE AMOUNTS

Where practical, or considered material to the reader, certain comparative amounts have been reclassified to conform with the current year's financial statement presentation.

2. CHANGES IN ACCOUNTING POLICIES

FINANCIAL INSTRUMENTS, COMPREHENSIVE INCOME AND HEDGING RELATIONSHIPS

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1530 *Comprehensive Income*, Section 3251 *Equity*, Section 3855 *Financial Instruments – Recognition and Measurement*, Section 3861 *Financial Instruments – Disclosure and Presentation* and Section 3865 *Hedges*. In accordance with the transitional provisions in these new standards, these policies were adopted prospectively and accordingly, the prior periods were not restated. Prior period unrealized gains and losses related to the Company's foreign currency translation adjustments and net investment hedges are now included in AOCI.

Comprehensive Income and Equity

The new standards introduced comprehensive income, which consists of earnings and OCI. The cumulative changes in OCI are recorded in AOCI, a separate component of shareholders' equity. The cumulative translation adjustment, previously presented as a separate component of shareholders' equity, is now presented as a component of AOCI. The components of AOCI are presented in Note 20.

Financial Instruments

CICA Handbook Section 3855 established recognition and measurement criteria for financial instruments and requires that, generally, all financial instruments are recorded at fair value on initial recognition. Subsequent measurement depends on whether the instrument has been classified as "held to maturity", "held for trading", "available for sale" or "loans and receivables" as defined by Section 3855.

With the exception of recognizing derivative instruments, including hedge instruments, at fair value, the carrying value of the Company's financial instruments did not change. The methods by which the Company determines the fair value of its financial instruments also did not change as a result of adopting this standard.

Impact on Adoption

The adoption of the new standards resulted in the following adjustments on January 1, 2007:

Increase/(Decrease)	Assets	Liabilities and Equity
(millions of Canadian dollars)		
Accounts receivable and other [1, 2]	5.4	–
Deferred amounts and other assets [1, 2, 3, 4]	55.3	–
Long-term investments [1]	(57.3)	–
Accounts payable and other [2]	–	57.6
Long-term debt [3]	–	(52.7)
Other long-term liabilities [1, 2, 4]	–	42.5
Future income taxes [1]	–	(18.9)
Non-controlling interests [1]	–	(26.3)
Accumulated other comprehensive income [1]	–	48.2
Retained earnings [1]	–	(47.0)
	3.4	3.4

1 As a result of the new standards for cash flow hedges, the Company recognized unrealized net gains related to interest rate, foreign exchange and commodity hedges. The Company adjusted both deferred amounts and retained earnings for historical fair value adjustments related to certain cash flow hedges.

2 The Company recorded a regulatory liability due to the recognition of fixed price power contracts offset by unrealized financial instrument losses.

3 The Company reclassified unamortized deferred financing fees from deferred amounts and other assets to long-term debt as a result of adopting the new standards.

4 Relates to the recognition of gas purchase hedges for the regulated gas distribution businesses at January 1, 2007.

CAPITAL DISCLOSURES AND FINANCIAL INSTRUMENTS – DISCLOSURES AND PRESENTATION

Effective January 1, 2008, the Company adopted new accounting standards for *Capital Disclosures* (CICA Handbook Section 1535) and *Financial Instruments – Disclosures and Presentation* (CICA Handbook Sections 3862 and 3863). While the new standards did not change the Company's accounting policies, they resulted in additional disclosures.

Under Section 1535, the Company disclosed its objectives, policies and procedures for managing capital, summary quantitative data about what the Company manages as capital, whether the Company has complied with any externally imposed capital requirements and, if the Company has not complied with them, any consequences of non-compliance with these capital requirements.

Sections 3862 and 3863 replaced Section 3861 *Financial Instruments – Disclosure and Presentation*. Disclosure requirements are revised and enhanced, while presentation requirements remain essentially unchanged. The new disclosure requirements have expanded disclosure about the significance of financial instruments for the Company's financial position and performance, the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks.

INVENTORIES

The CICA issued Section 3031 *Inventories* effective January 1, 2008 which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards (IFRS) and has replaced Section 3030. The adoption of the revised standard did not have a significant effect on the Company.

FUTURE ACCOUNTING POLICY CHANGES

Accounting for the Effects of Rate Regulation

In August 2007, the Canadian Accounting Standards Board (AcSB) published its decision with respect to rate regulated operations. The AcSB decided to retain much of the existing guidance related to rate-regulated operations; however, the exemption from the requirement to record future income taxes, as currently provided in CICA Handbook Section 3465 *Income Taxes* and the exemption from CICA Handbook Section 1100 *Generally Accepted Accounting Principles* will be removed, effective January 1, 2009. The Company will adopt these changes on January 1, 2009 and the principal effect will be the recognition of future income tax liabilities on the balance sheet, offset equally by regulatory assets *(Note 4)*.

Goodwill and Intangible Assets

The CICA implemented revisions to standards dealing with goodwill and intangible assets effective for fiscal years beginning on or after October 1, 2008. Section 3064 *Goodwill and Intangible Assets*, which replaces Section 3062 *Goodwill and Other Intangible Assets*, gives guidance on the recognition of intangible assets as well as the recognition and measurement of internally developed intangible assets. This standard is not expected to materially impact the Company's financial statements.

Business Combinations

The CICA issued Section 1582 *Business Combinations*, which replaces Section 1581. This new standard aligns accounting for business combinations under Canadian GAAP with IFRS and is effective for business combinations entered into on or after January 1, 2011. The adoption of the revised standard is expected to impact the Company's financial statements only to the extent that business combinations are entered into after the effective date.

International Financial Reporting Standards

The AcSB confirmed in February 2008 that publicly accountable entities will be required to adopt IFRS for interim and annual financial statements for periods beginning on January 1, 2011. The Company has established a project plan for implementing IFRS which includes determining:

- Changes to accounting policies and implementation decisions;
- Disclosure requirements;
- Changes to information systems and accounting processes;
- Changes to internal controls over financial reporting and disclosure controls and procedures;
- Training requirements; and
- External stakeholder communications.

The impact of the adoption of IFRS on the Company's financial reporting is not yet determinable.

3. SEGMENTED INFORMATION

Year ended December 31, 2008	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
(millions of Canadian dollars)							
Revenues	1,170.5	359.3	297.5	14,279.6	11.8	12.6	16,131.3
Commodity costs	–	–	–	(12,792.0)	–	–	(12,792.0)
Operating and administrative	(492.1)	(117.2)	(101.6)	(554.4)	(14.1)	(32.8)	(1,312.2)
Depreciation and amortization	(180.8)	(100.2)	(78.1)	(291.3)	(0.8)	(7.2)	(658.4)
	497.6	141.9	117.8	641.9	(3.1)	(27.4)	1,368.7
Income from equity investments	(0.2)	–	148.4	4.7	25.0	(0.8)	177.1
Other investment income and gain on sale of CLH	60.6	7.7	25.0	25.0	726.1	52.9	897.3
Interest and preferred share dividends	(111.4)	(68.8)	(59.9)	(201.0)	–	(116.6)	(557.7)
Non-controlling interest	(1.0)	–	(46.5)	(6.8)	–	(1.4)	(55.7)
Income taxes	(117.6)	(32.3)	(73.1)	(163.2)	(139.8)	17.1	(508.9)
Earnings applicable to common shareholders	328.0	48.5	111.7	300.6	608.2	(76.2)	1,320.8

Year ended December 31, 2007	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
millions of Canadian dollars							
Revenues	1,090.9	321.3	270.3	10,217.9	9.8	9.2	11,919.4
Commodity costs	–	–	–	(9,009.5)	–	–	(9,009.5)
Operating and administrative	(426.5)	(87.4)	(79.2)	(529.9)	[illegible]	[illegible]	[illegible]
Depreciation and amortization	(155.8)	(83.5)	(74.8)	(276.3)	(0.8)	(5.7)	(596.9)
	508.6	150.4	116.3	402.2	(5.2)	23.0	1,149.3
Income from equity investments	(0.6)	–	96.5	8.7	64.1	(0.9)	167.8
Other investment income	15.5	23.4	38.8	25.7	39.1	52.6	195.1
Interest and preferred share dividends	(100.9)	(64.2)	(61.9)	(207.1)	–	(122.8)	(556.9)
Non-controlling interest	(1.3)	–	(38.4)	(5.7)	–	(0.5)	(45.9)
Income taxes	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	66.5	[illegible]
Earnings applicable to common shareholders	287.2	69.7	96.9	179.4	95.1	18.1	700.1

Year ended December 31, 2006	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
millions of Canadian dollars							
Revenues	1,048.1	345.9	254.7	8,973.2	14.2	8.4	10,644.5
Commodity costs	–	–	–	(7,824.6)	–	–	(7,824.6)
Operating and administrative	(391.2)	(96.0)	[illegible]	(483.6)	(18.2)	(27.6)	(1,084.2)
Depreciation and amortization	(153.4)	[illegible]	[illegible]	(267.9)	(0.9)	(5.8)	(587.4)
	[illegible]	[illegible]	[illegible]	397.1	(4.9)	(24.9)	1,148.3
Income from equity investments	[illegible]	–	[illegible]	[illegible]	[illegible]	–	[illegible]
Other investment income	3.2	9.2	2.9	12.9	45.2	34.4	107.8
Interest and preferred share dividends	(102.4)	[illegible]	[illegible]	[illegible]	–	[illegible]	[illegible]
Non-controlling interest	(1.6)	–	(48.0)	(4.4)	–	(0.7)	(54.7)
Income taxes	(128.3)	(37.1)	(34.7)	(54.9)	(9.3)	72.0	(191.3)
Earnings applicable to common shareholders	274.2	61.2	86.8	173.7	83.2	(63.7)	615.4

The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 2.

1. Corporate includes new business development activities and investing and financing activities, including general corporate investments and financing costs not allocated to the business segments.

TOTAL ASSETS

December 31,	2008	[illegible]
(millions of Canadian dollars)		
Liquids Pipelines	7,466.7	[illegible]
Gas Pipelines	2,736.1	[illegible]
Sponsored Investments	3,765.5	[illegible]
Gas Distribution and Services	7,633.3	[illegible]
International	357.4	[illegible]
Corporate	2,744.4	[illegible]
	24,701.4	[illegible]

ADDITIONS TO PROPERTY, PLANT AND EQUIPMENT

December 31,	2008	[illegible]
(millions of Canadian dollars)		
Liquids Pipelines	2,904.8	[illegible]
Gas Pipelines	136.4	[illegible]
Sponsored Investments	57.8	[illegible]
Gas Distribution and Services	478.2	[illegible]
International and Corporate	117.0	[illegible]
	3,694.2	[illegible]

GEOGRAPHIC INFORMATION

Revenues [1]

December 31,	2008	[illegible]	[illegible]
(millions of Canadian dollars)			
Canada	12,447.8	[illegible]	[illegible]
United States	3,671.8	[illegible]	[illegible]
Other	11.7	[illegible]	[illegible]
	16,131.3	[illegible]	[illegible]

1 *Revenues are based on the country of origin of the product or services sold.*

PROPERTY, PLANT AND EQUIPMENT

December 31,	2008	[illegible]
(millions of Canadian dollars)		
Canada	12,338.3	[illegible]
United States	4,049.8	[illegible]
Other	1.5	[illegible]
	16,389.6	[illegible]

4. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation where the rates approved by the regulator are designed to recover the costs of providing the products and services referred to as the cost of service toll methodology. The Company's significant regulated businesses and related accounting impacts are described below.

Enbridge System

The primary business activities of the Enbridge System are subject to regulation by the NEB. Tolls are based on a cost of service methodology and are based on agreements with customers which are filed with the NEB for approval.

The incentive tolling settlement (ITS) is effective from January 1, 2005 to December 31, 2009 and defines the methodology for calculation of tolls and the revenue requirement on the core component of the Enbridge System in Canada. Toll adjustments, for variances from requirements defined in the ITS, are filed annually with the regulator for approval.

Athabasca Pipeline

Athabasca Pipeline is regulated by the ERCB. Tolls are established based on long-term transportation agreements with individual shippers and taxes are recorded using the taxes payable method.

Vector Pipeline

Vector Pipeline is an interstate natural gas pipeline with a FERC approved tariff establishing rates, terms and conditions governing its service to customers. Rates are determined using a cost of service methodology. Tariff changes may only be implemented upon approval by the FERC. Tolls include a return on equity component of 11.04% (2007 – 10.75%; 2006 – 10.75%) after tax.

Alliance Pipeline

The U.S. portion of the Alliance Pipeline (Alliance) is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on Alliance entered into 15-year transportation contracts expiring in December 2015, with a cost of service toll methodology. Toll adjustments are filed annually with the regulator. The tolls include a return on equity component of 10.88% (2007 – 10.88%; 2006 – 10.85%) after tax for the U.S. portion and 11.26% (2007 – 11.26%; 2006 – 11.25%) after tax for the Canadian portion. Alliance tolls are based on a deemed 70% debt and 30% equity structure.

Enbridge Gas Distribution

EGD's gas distribution operations are regulated by the OEB. EGD's rates are based on a revenue per customer cap incentive regulation (IR) methodology which adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions. Unlike the cost of service methodology used in prior years, the concepts of rate base and return on rate base are not relevant under IR.

EGD's rate of return on common equity embedded in rates was 8.39% (2007 – 8.39%; 2006 – 8.74%) after tax based on a 36% (2007 – 36%; 2006 – 35%) deemed common equity component of capital for regulatory purposes.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and follows a cost of service tolling methodology. An application for rate adjustments is filed annually for EUB approval. EGNB's rate of return on rate base was 9.71% (2007 – 9.70%; 2006 – 9.78%) after tax and the approved rate of return on equity was 13.00% (2007 – 13.00%; 2006 – 13.00%) after tax, based on equity which is capped at 50%.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated entities has resulted in recording the following regulatory assets and liabilities:

December 31,	2008	2007	Estimated Settlement Period (years)	Earnings Impact [1] 2008	2007	2006
(millions of Canadian dollars)						
Regulatory Assets/(Liabilities)						
Liquids Pipelines						
Enbridge System tolling deferrals [2]	**113.6**	143.4	1	**(29.8)**	(22.8)	(6.1)
Power purchase arrangements [3]	**(20.9)**	(23.8)	1-3	**2.9**	(23.8)	–
Gas Pipelines						
Deferred transportation revenue [4]	**266.7**	181.4	15-17	**1.1**	5.9	9.8
Transportation revenue adjustment [5]	**6.7**	4.1	1	**0.9**	(2.6)	(1.4)
Sponsored Investments						
Deferred transportation revenue [4]	**79.8**	65.6	17	**5.9**	7.7	7.3
Gas Distribution and Services						
EGNB regulatory deferral [6]	**132.7**	117.7	32	**10.1**	10.3	12.4
Class action lawsuit settlement [7]	**20.1**	22.0	4	**(1.2)**	–	13.5
Ontario hearing cost [8]	**5.3**	8.1	2	**(1.8)**	(0.7)	(1.7)
Purchased gas variance [9]	**(75.2)**	(141.1)	1	**43.8**	(8.8)	(99.3)
Unaccounted for gas variance [10]	**0.6**	6.1	1	**(3.6)**	11.4	(9.4)
Transactional services deferral [11]	**(6.5)**	(8.8)	1	**–**	–	–

1 *The effect of a number of the Company's businesses being subject to rate regulation increased / (decreased) after tax reported earnings by the identified amounts.*

2 *Tolls on the Enbridge System are calculated in accordance with the ITS, System Expansion Program (SEP) II and the Terrace agreements and are established each year based on capacity, the allowed revenue requirement and the Terrace agreement. Where actual volumes shipped on the pipeline do not result in collection of the annual revenue requirement, a receivable is recognized and incorporated into tolls in the subsequent year. Recovery in the subsequent year, in whole or in part, is dependent upon realizing shipping volumes consistent with tolling model forecasts. Under/over collection are rolled into subsequent years. In addition, other tolling deferrals are recorded in accordance with the various agreements.*

3 *The power purchase arrangements liability represents the fair value of fixed price contracts and related financial instruments used to manage the mix of fixed and floating power costs (Note 21).* Under rate regulation any fair value changes are passed to shippers through tolls. In the absence of rate regulation, these changes would impact earnings in the year incurred.

4 *Deferred transportation revenue is related to the cumulative difference between GAAP depreciation expense of Alliance and Vector Pipelines and depreciation expense included in the regulated transportation rates. The Company expects to recover this difference over a number of years when depreciation rates in the transportation agreements are expected to exceed the GAAP depreciation rates, for Alliance US beginning in 2009 and Alliance Canada beginning in 2012 and ending in 2025 and for Vector beginning in 2008 and ending in 2023. This regulatory asset is not included in the rate base.*

5 *The transportation revenue adjustment is the cumulative difference between actual expenses of Alliance Pipeline US and estimated expenses included in transportation rates. The transportation revenue adjustment is recoverable under the long-term transportation agreements and is not included in the rate base.*

6 *A regulatory deferral account captures the difference between EGNB's distribution revenues and its cost of service revenue requirement during the development period. The regulatory deferral account balance will be amortized over a recovery period approved by the EUB, currently expected to end after 2040, commencing at the end of the development period which is expected to be 2010.*

7 *Class action lawsuit settlement deferral represents amounts paid towards the settlement of a class action lawsuit related to late payment penalties. Pursuant to an OEB decision in February 2008, these amounts will be recovered from customers over a five-year period commencing in 2008. In the absence of rate regulation these costs would be expensed as incurred.*

8 *Ontario hearing costs are incurred by EGD for the rate hearing process. EGD has historically been granted OEB approval for recovery of such hearing costs, generally within two years. In the absence of rate regulation these costs would be expensed as incurred.*

9 *Purchased gas variance is the difference between the actual cost and the approved cost of gas reflected in rates. EGD has historically been granted approval for recovery or required refund of this variance within the year. In the absence of rate regulation the actual cost of gas sold would be recognized in earnings in the year sold.*

10 *Unaccounted for gas variance represents the difference between the total gas distributed by EGD and the amount of gas billed or billable to ratepayers, to the extent it is different from the approved gas variance. EGD has deferred unaccounted for gas variance and has historically been granted approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation this variance would be included in cost of sales.*

11 *Transactional services deferral represents the ratepayer portion of excess earnings generated from optimization of storage and pipeline capacity. EGD has historically been required to refund the amount to ratepayers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Future Income Taxes

In the absence of rate regulation, future income tax liabilities of $532.9 million (2007 – $517.1 million) associated with certain assets, primarily property, plant and equipment, would be recorded.

The Company has recorded net future income tax liabilities of $67.7 million (2007 – $24.0 million) related to certain regulatory asset/liability deferral accounts identified above. Accumulated future income tax liabilities of $54.5 million (2007 – $55.6 million) related to the remaining regulatory deferral accounts have not been recognized at December 31, 2008. In the absence of rate regulation, regulatory deferrals would not be recorded nor would the associated future income tax liabilities. As a result of these tax impacts, earnings during the year would decrease by $15.0 million (2007 – increase by $62.2 million).

Allowance For Funds Used During Construction and Other Capitalized Costs

With the pool method prescribed by regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains or losses on the retirement of specific fixed assets in any given year cannot be identified or quantified.

Operating Cost Capitalization

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2008, $93.7 million (2007 – $82.2 million) was included in gas mains, which are depreciated over the average service life of 25 years. In the absence of rate regulation, the majority of these costs would be charged to current earnings.

Pension Plans

Had pension costs and obligations been recognized at EGD, the net pension asset would have increased by $156.1 million at December 31, 2008 (2007 – $153.3 million) and earnings would have increased by $3.1 million (2007 – decreased by $1.1 million).

Post-Employment Benefits Other than Pensions

In the absence of rate regulation, the cost of such benefits is accrued during the years employees render service. Had these costs been accrued at EGD, the net OPEB liability would have increased by $75.5 million (2007 – $70.8 million) and earnings would have decreased by $5.5 million (2007 – $5.8 million).

5. DISPOSITION AND ACQUISITION

DISPOSITION

On June 17, 2008, the Company sold its 25% investment in CLH for total proceeds of $1.38 billion (876 million euros), including a dividend receivable of $17.3 million (10.9 million euros), net of transaction costs. The sale of CLH resulted in a gain of $694.6 million. Earnings generated by the CLH investment were $24.7 million (2007 – $65.6 million; 2006 – $54.5 million) for the year ended December 31, 2008, and are included in the International operating segment. Operating cash flows generated by the CLH investment were $11.5 million for the year ended December 31, 2008 (2007 – $58.4 million; 2006 – $56.2 million).

ACQUISITION

On February 1, 2006, Enbridge acquired a 65% common share interest in the Olympic Pipe Line Company for $112.7 million in cash.

(millions of Canadian dollars)	
Fair Value of Assets Acquired:	
Property, plant and equipment	107.0
Other assets	5.0
Future income taxes	(6.1)
Other liabilities	(17.0)
	88.9
Goodwill	23.8
	112.7
Purchase Price:	
Cash, net of $1.6 million cash acquired	112.7
Deposit paid in 2005	(11.3)
	101.4

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2008**	2007
(millions of Canadian dollars)		
Trade receivables	**1,088.4**	1,332.4
Unbilled revenues	**569.8**	453.0
Regulatory assets	**144.6**	183.7
Taxes receivable	**133.3**	17.6
GST receivable	**74.6**	78.7
Short-term portion of derivative assets	**65.3**	79.5
Prepaid expenses and deposits	**28.4**	20.2
Transfer fees	**22.3**	28.9
Due from affiliates	**18.3**	75.0
Dividends receivable	**13.3**	12.2
Other	**164.2**	107.5
	2,322.5	2,388.7

7. INVENTORY

December 31,	**2008**	2007
(millions of Canadian dollars)		
Gas	**674.3**	599.2
Other commodities	**170.4**	110.2
	844.7	709.4

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2008	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Liquids Pipelines				
Pipeline	2.4%	3,161.9	1,359.6	1,802.3
Pumping equipment, buildings, tanks and other	3.7%	3,025.7	1,027.8	1,997.9
Land and right-of-way	2.5%	69.9	19.7	50.2
Under construction	–	3,856.9	–	3,856.9
		10,114.4	2,407.1	7,707.3
Gas Pipelines				
Pipeline	3.6%	2,169.0	588.7	1,580.3
Land and right-of-way	2.8%	48.6	11.3	37.3
Metering and other	5.5%	168.7	28.9	139.8
Under construction	–	333.5	–	333.5
		2,719.8	628.9	2,090.9
Sponsored Investments				
Pipeline	4.4%	1,362.9	276.7	1,086.2
Other	8.7%	129.0	16.1	112.9
		1,491.9	292.8	1,199.1
Gas Distribution and Services				
Gas mains	3.7%	2,943.7	804.1	2,139.6
Gas services	4.1%	2,290.5	739.4	1,551.1
Regulating and metering equipment	3.7%	619.1	177.3	441.8
Storage	2.7%	246.5	67.3	179.2
Computer technology	19.1%	158.3	62.5	95.8
Other	4.5%	541.6	124.8	416.8
Under construction	–	26.7	–	26.7
		6,826.4	1,975.4	4,851.0
International and Corporate				
Wind turbines and other	4.9%	552.0	34.0	518.0
Land and right-of-way	4.0%	1.8	–	1.8
Under construction	–	21.5	–	21.5
		575.3	34.0	541.3
		21,727.8	5,338.2	16,389.6

December 31, 2007 *(millions of Canadian dollars)*	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	2.2%	2,688.4	1,259.9	1,428.5
Pumping equipment, buildings, tanks and other	3.7%	2,566.6	912.1	1,654.5
Land and right-of-way	1.8%	41.5	18.5	23.0
Under construction	–	1,546.4	–	1,546.4
		6,842.9	2,190.5	4,652.4
Gas Pipelines				
Pipeline	3.7%	1,656.5	390.4	1,266.1
Land and right-of-way	2.7%	38.8	7.6	31.2
Metering and other	4.6%	101.6	16.0	85.6
Under construction	–	272.6	–	272.6
		2,069.5	414.0	1,655.5
Sponsored Investments				
Pipeline	4.2%	1,402.8	284.1	1,118.7
Other	7.6%	108.7	13.9	94.8
		1,511.5	298.0	1,213.5
Gas Distribution and Services				
Gas mains	3.3%	2,748.9	708.7	2,040.2
Gas services	3.6%	2,224.0	676.4	1,547.6
Regulating and metering equipment	3.7%	581.9	158.0	423.9
Storage	2.7%	246.4	61.0	185.4
Computer technology	19.4%	185.2	81.6	103.6
Other	4.6%	310.6	106.5	204.1
Under construction	–	143.1	–	143.1
		6,440.1	1,792.2	4,647.9
International and Corporate				
Other	8.1%	113.0	37.3	75.7
Under construction	–	352.6	–	352.6
		465.6	37.3	428.3
		17,329.6	4,732.0	12,597.6

9. JOINT VENTURES

Enbridge has joint venture interests in the following entities:

December 31,	Ownership Interest	Net Assets 2008	Net Assets 2007
(millions of Canadian dollars)			
Liquids Pipelines			
Olympic Pipeline	65%	**125.3**	97.8
Chicap Pipeline *(Note 10)*	43.8%	**53.8**	–
Other	30%-50%	**59.5**	54.8
Gas Pipelines			
Alliance Pipeline US	50%	**452.9**	364.3
Vector Pipeline	60%	**486.3**	408.4
Enbridge Offshore Pipelines – various joint ventures	22%-75%	**521.1**	441.3
Sponsored Investments			
Alliance Pipeline Canada	50%	**344.4**	354.8
Other	33%-50%	**47.7**	69.2
Gas Distribution and Services			
Aux Sable	42.7%	**173.6**	150.6
Other	42.7%-70%	**44.6**	49.7
		2,309.2	1,990.9

The following summarizes the impact of proportionately consolidating the joint ventures on the consolidated financial statements of Enbridge:

Year ended December 31,	2008	2007	2006
(millions of Canadian dollars)			
Earnings			
Revenues	**891.0**	844.5	939.4
Commodity costs	**(173.6)**	(132.9)	(184.8)
Operating and administrative	**(235.4)**	(207.6)	(257.2)
Depreciation and amortization	**(167.7)**	(152.9)	(164.8)
Interest expense	**(102.1)**	(106.4)	(110.8)
Other investment income	**12.7**	6.6	7.3
Proportionate share of earnings	**224.9**	251.3	229.1
Cash Flows			
Cash provided by operating activities	**407.7**	312.0	318.3
Cash used in investing activities	**(61.2)**	(131.9)	(59.5)
Cash used in financing activities	**(350.6)**	(183.9)	(258.9)
Proportionate share of decrease in cash and cash equivalents	**(4.1)**	(3.8)	(0.1)

December 31, (millions of Canadian dollars)	2008	2007
Financial Position		
Current assets	**179.2**	146.0
Property, plant and equipment, net	**3,268.9**	2,913.1
Deferred amounts and other assets	**335.6**	277.6
Current liabilities	**(176.9)**	(139.8)
Non-recourse long-term debt	**(1,271.2)**	(1,181.6)
Other long-term liabilities	**(26.4)**	(24.4)
Proportionate share of net assets	**2,309.2**	1,990.9

During the year the Company purchased additional equity interest in Chicap Pipeline, increasing its ownership percentage to 43.8%. As the Company now has joint control over the entity, it has been proportionally consolidated as a joint venture in 2008. The entity was previously classified as a long-term investment *(Note 10)*.

10. LONG-TERM INVESTMENTS

December 31, (millions of Canadian dollars)	Ownership Interest	2008	2007
Equity Investments			
Liquids Pipelines			
Chicap Pipeline	–	–	17.2
Sponsored Investments			
The Partnership	27.0%	**2,013.2**	944.8
Gas Distribution and Services			
Noverco Common Shares	32.1%	**10.8**	11.6
Other		–	1.5
International			
Compañía Logística de Hidrocarburos CLH, S.A.	–	–	626.4
Corporate	10%-35%	**9.1**	16.1
Other Investments			
Gas Distribution and Services			
Noverco Preferred Shares		**181.4**	181.4
Fuel Cell Energy		**25.0**	25.0
International			
Oleoducto Central S.A.		**223.3**	223.3
Corporate			
Value Creation		**29.0**	29.0
		2,491.8	2,076.3

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the purchase date of $129.8 million at December 31, 2008 (2007 – $581.1 million). The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values and is amortized over the economic life of the assets. Consolidated retained earnings at December 31, 2008 include undistributed earnings from equity investments of $9.5 million (2007 – $5.0 million).

THE PARTNERSHIP

The Company has a combined 27.0% ownership in EEP, through a 2.0% general partner interest, a 13.9% interest in Class A units, a 3.4% interest in Class B units, a 5.5% interest in Class C units and a 2.2% interest in EEP via a 17.2% investment in EEM, which owns 14.7% of EEP via its 100% interest in EEP's i-units. The Company recorded investment income from EEP of $161.6 million (2007 – $130.4 million; 2006 – $111.5 million) including dilution gains.

Although 82.8% of EEM is widely held, the Company has voting control and; therefore, consolidates EEM, including its investment in EEP of $691.0 million (2007 – $456.4 million). Net of non-controlling interest in EEM, the book value of the Company's investment in EEP is $1,440.9 million (2007 – $566.7 million.)

In the second quarter of 2007, EEP issued Class A and Class C partnership units. As Enbridge did not fully participate in these offerings, dilution gains net of tax and non-controlling interest of $11.8 million resulted and Enbridge's ownership interest in the Partnership decreased from 16.6% to 15.1%.

In March 2008, EEP issued Class A units and, because Enbridge did not fully participate, a dilution gain of $4.5 million resulted and Enbridge's ownership interest in EEP decreased from 15.1% to 14.6%.

In November 2008, the Company subscribed for 16.3 million Class A common units of EEP for US$500.0 million increasing its ownership interest from 14.6% to 27.0%. The units were acquired by the Company's subsidiary EEC which also contributed approximately US$10.0 million to maintain its 2.0% general partner interest.

In 2006, the Company acquired 5.4 million Class C units of EEP for $280.2 million. The Class C units have the same voting rights as Class A and B units and are entitled to quarterly distributions equal to those paid to Class A and B unitholders. Prior to August 15, 2009, distributions are paid in additional Class C units, where Class C units are valued at the market value of Class A units. After August 15, 2009, distributions will be paid in cash and, subject to the approval of existing Class A and Class B unitholders, Class C units will convert into Class A units on a one-to-one basis. If approval of the conversion is not received, the Class C units will receive cash distributions equal to 115% of those paid to Class A unitholders.

NOVERCO

The Company owns a preferred share investment in Noverco of $181.4 million (2007 – $181.4 million), which is entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus 4.34%.

The Company also owns an equity investment in the common shares of Noverco of $10.8 million (2007 – $11.6 million). Noverco owns an approximate 9.3% (2007 – 9.5%) reciprocal shareholding in the shares of the Company. As a result, the Company has an indirect pro-rata interest of 3.0% (2007 – 3.1%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $154.3 million (2007 – $154.3 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from the earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco. In 2008, the Company recorded equity investment earnings of $4.4 million (2007 – $8.5 million; 2006 – $16.8 million) related to its interest in Noverco.

CORPORATE

The Company reviews the carrying value of its long-term investments on a regular basis as events or changes in circumstances warrant. During 2008, one of the Company's equity investments, N-Solv, a developer of in-situ oil sands extraction technology, failed a key milestone when its planned demonstration pilot plant was terminated. A writedown of $7.2 million was taken to adjust the carrying value of the investment to its fair value of $6.8 million.

CLH

On June 17, 2008, the Company sold its 25% equity interest in CLH *(Note 5)*.

OCENSA

The Company owns an investment in OCENSA, a crude oil export pipeline in Colombia of $223.3 million (US$160.2 million) (2007 – $223.3 million; US$160.2 million), which earns a fixed rate of return.

11. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2008**	2007
(millions of Canadian dollars)		
Regulatory deferrals	**510.2**	428.2
Contractual receivables	**158.7**	152.0
Long-term portion of derivative assets *(Note 22)*	**316.9**	329.0
Pension asset	**78.3**	72.3
Affiliate long-term note receivable (US$130.0 million) *(Note 28)*	**159.2**	128.5
Other	**95.1**	72.0
	1,318.4	1,182.0

At December 31, 2008, deferred amounts of $42.4 million (2007 – $42.3 million) were subject to amortization and are presented net of accumulated amortization of $23.5 million (2007 – $23.2 million). Amortization expense in 2008 was $3.0 million (2007 – $3.6 million; 2006 – $10.1 million).

12. INTANGIBLE ASSETS

December 31, 2008	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Transportation agreements	4.2%	**268.1**	**50.1**	**218.0**
Customer lists	7.1%	**10.3**	**3.0**	**7.3**
		278.4	**53.1**	**225.3**

December 31, 2007	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Transportation agreements	4.2%	241.8	36.3	205.5
Customer lists	7.1%	8.3	1.8	6.5
		250.1	38.1	212.0

Total amortization expense for intangible assets was $10.6 million for the year ended December 31, 2008 (2007 – $10.4 million; 2006 – $11.0 million). In the next five years, the Company expects the following aggregate amortization expense.

(millions of Canadian dollars)	
2009	9.7
2010	9.3
2011	8.9
2012	8.5
2013	8.1

13. GOODWILL

	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	Corporate	Consolidated
(millions of Canadian dollars)						
Balance at January 1, 2007	24.5	29.9	308.1	19.3	13.1	394.9
Foreign exchange and other	(6.2)	(4.6)	–	3.9	–	(6.9)
Balance at December 31, 2007	18.3	25.3	308.1	23.2	13.1	388.0
Goodwill impairment	–	–	–	–	**(13.1)**	**(13.1)**
Foreign exchange and other	**4.4**	**6.1**	–	**3.8**	–	**14.3**
Balance at December 31, 2008	**22.7**	**31.4**	**308.1**	**27.0**	–	**389.2**

In the fourth quarter of 2008, the Company concluded that the goodwill of Ontario Wind Power, within the Corporate business segment, was impaired. Accordingly an impairment loss of $13.1 million was recorded.

14. ACCOUNTS PAYABLE AND OTHER

December 31,	2008	2007
(millions of Canadian dollars)		
Trade payables	**548.0**	904.7
Operating accrued liabilities	**1,013.7**	860.0
Construction payables	**273.5**	166.9
Taxes payable	**272.9**	53.8
Security deposits	**122.8**	120.4
Other	**112.8**	79.5
Contractor holdbacks	**67.8**	28.5
	2,411.5	2,213.8

15. DEBT

December 31,	Weighted Average Interest Rate	Maturity	2008	2007
(millions of Canadian dollars)				
Liquids Pipelines				
Debentures	8.20%	2024	**200.0**	200.0
Medium-term notes	5.88%	2009-2036	**1,124.6**	824.6
Southern Lights project financing (US$850.0 million; 2007 – nil)			**1,358.9**	–
Commercial paper and credit facility draws, net (2008 – nil; 2007 – US$365.0 million)			**524.7**	500.6
Other [1]			**15.3**	15.9
Gas Distribution and Services				
Debentures	11.06%	2009-2024	**485.0**	485.0
Medium-term notes	5.77%	2014-2036	**1,795.0**	1,865.0
Commercial paper and credit facility draws, net			**883.2**	555.0
Corporate				
U.S. dollar term notes (US$1,372.0 million; 2007 – US$1,354.3 million)	5.50%	2014-2022	**1,680.2**	1,341.2
Medium-term notes	5.69%	2010-2035	**1,568.0**	1,900.0
Commercial paper and credit facility draws, net (US$690.0 million; 2007 – US$317.0 million)			**2,034.1**	1,353.5
Deferred debt issue costs and other			**(105.7)**	(161.0)
Total Debt			**11,563.3**	8,879.8
Current Maturities			**(533.8)**	(605.2)
Short-Term Borrowings	2.89%		**(874.6)**	(545.6)
Long-Term Debt			**10,154.9**	7,729.0

1 *Primarily capital leases.*

Debenture and term note maturities for the years ending December 31, 2009 through 2013 are $533.8 million, $600.7 million, $150.8 million, $250.9 million and $200.9 million, respectively. The Company's debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2009 through 2013 are $438.7 million, $379.8 million, $342.4 million, $333.9 million and $318.0 million, respectively.

INTEREST EXPENSE

Year ended December 31, (millions of Canadian dollars)	2008	2007	2006
Debentures and term notes	**403.9**	417.7	395.3
Southern Lights project financing	**27.6**	–	–
Non-recourse long-term debt	**100.0**	102.0	104.9
Commercial paper and credit facility draws	**100.3**	91.5	87.5
Capitalized	**(81.0)**	(61.2)	(20.6)
	550.8	550.0	567.1

In 2008, total interest paid was $606.8 million (2007 – $607.3 million; 2006 – $563.3 million).

CREDIT FACILITIES

December 31, 2008 (millions of Canadian dollars)	Expiry Dates	Total Facilities	Credit Facility Draws	Commercial Paper Backstop	Available
Liquids Pipelines	2010-2011	**1,300.0**	**525.5**	–	**774.5**
Gas Distribution and Services	2009-2010	**1,014.7**	**11.1**	**874.5**	**129.1**
Corporate [1]	2010-2013	**4,185.8**	**962.3**	**1,075.1**	**2,148.4**
		6,500.5	**1,498.9**	**1,949.6**	**3,052.0**
Southern Lights project financing [2]	2014	**2,028.1**	**1,358.9**	–	**669.2**
Credit facilities		**8,528.6**	**2,857.8**	**1,949.6**	**3,721.2**

1 *Total facilities exclusive of $49.0 million commitment of Lehman Brothers Bank given the bankruptcy filing of its parent in September 2008.*

2 *Total facilities inclusive of $140.2 million which is available if certain conditions related to the project are met.*

Credit facilities carry a weighted average standby fee of 0.252% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a backstop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2009 to 2014. See Note 31.

Commercial paper and credit facility draws, net of short-term borrowings, of $2,567.4 million (2007 – $1,863.5 million) are supported by the availability of long-term committed credit facilities and therefore has been classified as long-term debt.

16. NON-RECOURSE DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2008**	2007
(millions of Canadian dollars)				
Gas Pipelines				
Long-term credit facilities				
(US$1.0 million; 2007 – US$1.9 million)		2012	**1.2**	1.9
Senior notes				
(US$413.8 million; 2007 – US$441.8 million)	6.76%	2015-2025	**506.8**	436.5
Capital lease obligations	10.62%	2013-2020	**47.4**	39.9
Sponsored Investments				
Credit facilities		2011-2012	**174.1**	141.5
Medium term notes	4.69%	2009-2014	**190.0**	190.0
Senior notes	6.86%	2015-2025	**679.0**	707.7
Fair value increment on senior notes acquired			**38.2**	43.3
Gas Distribution and Services				
Term debt				
(US$21.6 million; 2007 – US$15.7 million)	4.10%	2009-2010	**26.6**	15.5
Capital lease obligations	12.00%	2016-2021	**5.7**	4.9
Deferred debt issue costs			**(10.3)**	(11.7)
Total Non-Recourse Debt			**1,658.7**	1,569.5
Current Maturities			**(184.7)**	(61.1)
Non-Recourse Long-Term Debt			**1,474.0**	1,508.4

Long-term debt maturities on non-recourse borrowings for the years ending December 31, 2009 through 2013 are $184.7 million, $92.4 million, $76.4 million, $81.9 million and $144.2 million, respectively. The medium term notes and senior notes bear interest at fixed rates.

Interest obligations on non-recourse borrowings for the years ending December 31, 2009 through 2013 are $93.8 million, $85.0 million, $79.4 million, $74.0 million and $68.1 million, respectively.

Certain assets of Alliance Pipeline Canada, with a carrying value of $1.1 billion, are pledged as collateral to Alliance Pipeline Canada's lenders and to the lenders to Alliance Pipeline US. As well, certain assets of Alliance Pipeline US, with a carrying value of $1.0 billion, are pledged as collateral to Alliance Pipeline US's lenders and to the lenders to Alliance Pipeline Canada.

Non-recourse debt has a fair value of $1,671.7 million (2007 – $1,634.8 million).

17. NON-CONTROLLING INTERESTS

December 31,	**2008**	2007
(millions of Canadian dollars)		
EEM	**481.0**	335.1
EGD Preferred Shares	**100.0**	100.0
EIF	**146.9**	155.9
EGNB	**57.1**	48.8
Other	**12.4**	10.7
	797.4	650.5

Non-controlling interest in EEM represents the 82.8% of the listed shares of EEM not held by the Company.

The Company owns 100% of the common shares of EGD; however, the 4,000,000 4.82% Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. Subsequent to July 1, 2009, EGD may, at its option, redeem all or a portion of the outstanding preferred shares for $25.00 plus all accrued and unpaid dividends to the redemption date. The preferred shares have no fixed maturity date.

Non-controlling interest in EIF represents 58.1% of voting units which are held by public unitholders. Non-controlling interest in EGNB represents 29.1% held by third parties.

18. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preferred shares.

COMMON SHARES

	2008		2007		2006	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**368.5**	**3,026.5**	351.8	2,416.1	348.9	2,343.8
Common shares issued	**–**	**–**	15.0	566.4	–	–
Exercise of stock options	**1.3**	**36.2**	1.2	26.3	2.4	53.9
Dividend Reinvestment and Share Purchase Plan	**3.2**	**131.3**	0.5	17.7	0.5	18.4
Balance at end of year	**373.0**	**3,194.0**	368.5	3,026.5	351.8	2,416.1

PREFERRED SHARES

The 5.0 million 5.5% Cumulative Redeemable Preferred Shares, Series A are entitled to fixed, cumulative, quarterly preferential dividends of $1.375 per share per year. The Company may, at its option, redeem all or a portion of the outstanding preferred shares for $25.00 per share plus all accrued and unpaid dividends.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 11.1 million shares (2007 – 11.1 million shares), resulting from the Company's reciprocal investment in Noverco.

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes that any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

December 31,	**2008**	2007	2006
(number of common shares in millions)			
Weighted average shares outstanding	**359.8**	355.3	340.0
Effect of dilutive options	**3.3**	3.0	3.3
Diluted weighted average shares outstanding	**363.1**	358.3	343.3

For the year ended December 31, 2008, 2,879,800 anti-dilutive stock options (2007 – 1,158,200; 2006 – 1,548,900) with a weighted average exercise price of $40.53 (2007 – $38.26; 2006 – $36.47) were excluded from the diluted earnings per share calculation.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Under the Dividend Reinvestment and Share Purchase Plan, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges. Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties, acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

19. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains four long-term incentive compensation plans: the Incentive Stock Option (ISO) Plan, the Performance Based Stock Option (PBSO) Plan, the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan. A maximum of 30 million common shares were reserved for issuance under the 2002 ISO plan, of which 16 million have been issued to date. In 2007, a new reserve of 16.5 million shares was approved and established for the 2007 ISO and PBSO plans, of which none have been issued to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date. Compensation expense recorded for the year ended December 31, 2008 for ISOs is $13.0 million (2007 – $9.0 million; 2006 – $10.5 million).

Outstanding Incentive Stock Options

	2008		2007		2006	
December 31,	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercised Price
(options in thousands; exercise price in Canadian dollars)						
Options at beginning of year	**9,237**	**27.24**	9,186	24.97	9,434	22.09
Options granted	**2,642**	**40.54**	1,158	38.26	1,595	36.41
Options exercised	**(1,178)**	**21.85**	(1,046)	19.21	(1,698)	19.38
Options cancelled or expired	**(51)**	**36.83**	(61)	32.97	(145)	28.81
Options at end of year	**10,650**	**31.05**	9,237	27.24	9,186	24.97
Options vested	**6,087**	**25.32**	5,865	22.87	5,323	20.54

The total intrinsic value of ISOs exercised during the year ended December 31, 2008 was $22.9 million (2007 – $19.1 million; 2006 – $27.8 million) and cash received on exercise was $25.7 million (2007 – $20.1 million; 2006 – $32.9 million). Intrinsic value represents the difference between the Company's share price and the exercise price, multiplied by the number of options. The total intrinsic value of ISOs outstanding and vested at December 31, 2008 was $109.0 million and $97.2 million, respectively.

Incentive Stock Option Characteristics

December 31, 2008	Options Outstanding			Options Vested		
Exercise Price Range	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
10.00-14.99	**401**	**1.2**	**13.30**	**401**	**1.2**	**13.30**
15.00-19.99	**731**	**1.7**	**18.55**	**731**	**1.7**	**18.55**
20.00-24.99	**1,914**	**3.6**	**21.30**	**1,914**	**3.6**	**21.30**
25.00-29.99	**1,189**	**5.0**	**25.74**	**1,189**	**5.0**	**25.74**
30.00-34.99	**1,252**	**6.1**	**31.79**	**892**	**6.0**	**31.75**
35.00-39.99	**2,533**	**7.5**	**37.26**	**960**	**7.4**	**36.98**
40.00-44.99	**2,072**	**9.1**	**40.42**	**–**	**–**	**–**
45.00-49.99	**558**	**9.1**	**49.61**	**–**	**–**	**–**
	10,650	**6.1**	**31.54**	**6,087**	**4.4**	**25.32**

The total fair value of options vested for the ISO Plan was $9.1 million at December 31, 2008 (2007 – $7.5 million; 2006 – $5.8 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes option pricing model are as follows:

Year ended December 31,	**2008**	2007	2006
Fair value per option *(Canadian dollars)* [1]	**6.14**	6.16	6.30
Valuation assumptions			
Expected option term *(years)* [2]	**6**	6	8
Expected volatility [3]	**18.48%**	18.10%	19.00%
Expected dividend yield [4]	**3.34%**	3.22%	3.23%
Risk-free interest rate [5]	**3.50%**	4.11%	4.16%

1 *Beginning in 2008, options granted to U.S. employees are based on NYSE prices. The option value and assumptions shown for 2008 are based on a weighted average of the U.S. options and the Canadian options. The fair values per option were $6.20 for Canadian employees and US$5.82 for U.S. employees.*

2 *The expected option term is based on historical information.*

3 *Expected volatility is based on historical information from both the Toronto Stock Exchange and the New York Stock Exchange.*

4 *The expected dividend yield is the current annual dividend divided by the current stock price.*

5 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the U.S. Treasury Bond Yields.*

As of December 31, 2008, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO plan was $9.7 million. The cost is expected to be recognized over a period of 2.5 years.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on September 16, 2002, August 15, 2007 and February 19, 2008. The 2008 PBSO grant is included in the 2007 PBSO plan. All performance targets and time vesting requirements for the 2002 PBSO grant have been met. The 2002 PBSO grant will expire on September 16, 2010. The 2007 and 2008 PBSO grants performance targets are based on the Company's share price. Time vesting requirements for the 2007 PBSO grant are fulfilled evenly over a five-year term, ending August 15, 2012. Time vesting requirements for the 2008 PBSO grant were modified to a four and a half year term and will be completed concurrently with the 2007 grant on August 15, 2012. Under the 2007 PBSO plan performance vesting targets must be met by February 15, 2014, otherwise the options expire. If targets are met by February 15, 2014, the options are exercisable until August 15, 2015. Compensation expense recorded for the year ended December 31, 2008 for PBSOs was $1.8 million (2007 – $0.7 million).

Outstanding Performance Based Stock Options

	2008		2007		2006	
December 31,	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
Options at beginning of year	**3,588**	**31.92**	1,379	23.15	2,105	21.57
Options granted	**250**	**40.42**	2,345	36.57	–	–
Options exercised	**(100)**	**23.15**	(136)	23.15	(645)	18.00
Options cancelled	**–**	**–**	–	–	(81)	23.15
Options at end of year	**3,738**	**32.72**	3,588	31.92	1,379	23.15
Options vested	**1,143**	**23.15**	1,243	23.15	1,119	23.15

The total intrinsic value of PBSOs exercised during the year ended December 31, 2008 was $1.8 million (2007 – $1.9 million; 2006 – $11.4 million) and cash received on exercise was $2.3 million (2007 – $3.1 million; 2006 – $11.6 million). The total intrinsic value of PBSOs outstanding and vested at December 31, 2008 is $32.0 million and $20.7 million, respectively.

Performance Based Stock Option Characteristics

December 31, 2008	Options Outstanding			Options Vested		
Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
23.15	**1,143**	**1.7**	**23.15**	**1,143**	**1.7**	**23.15**
36.57	**2,345**	**6.6**	**36.57**	**–**	**–**	**–**
40.42	**250**	**6.6**	**40.42**	**–**	**–**	**–**
	3,738	**5.1**	**32.72**	**1,143**	**1.7**	**23.15**

The total fair value of options vested for the PBSO Plan was $1.8 million at December 31, 2008 (2007 – $1.7 million; 2006 – $1.2 million).

Assumptions used to determine the fair value of the PBSOs using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	2008	2007
Fair value per option *(Canadian dollars)*	**4.82**	3.40
Valuation assumptions		
Expected option term *(years)* [1]	**8**	8
Expected volatility [1]	**13.60%**	13.60%
Expected dividend yield [2]	**3.32%**	3.57%
Risk-free interest rate [3]	**3.75%**	4.38%

1 *The expected option term and the expected volatility are based on historical information.*

2 *The expected dividend yield is the current annual dividend divided by the current stock price.*

3 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the U.S. Treasury Bond Yields.*

As of December 31, 2008, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the PBSO plan was $6.7 million. The cost is expected to be recognized over a period of 3.7 years.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price and by a performance multiplier. The performance multiplier ranges from 0, if the Company's performance fails to meet threshold performance levels, to a maximum of 2, if the Company

performs within the highest range of its performance targets. The performance multiplier for the 2006 grant was based on the Company's total shareholder return over the three-year performance period relative to a specified peer group of companies. The 2007 and 2008 grants derive the performance multiplier through a calculation of the Company's Price/Earnings ratio relative to a specified peer group of companies and the Company's growth in earnings per share relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2008 for PSUs was $12.6 million (2007 – $3.0 million; 2006 – $4.1 million). An estimated performance multiplier of 1.62, 1.45 and 1.93 was used to calculate the expense based upon historical performance for the 2006, 2007 and 2008 grants, respectively.

Outstanding Performance Stock Units

December 31,	**2008**	2007	2006
Units at beginning of year	**267,616**	328,716	200,652
Units granted	**144,300**	137,200	117,900
Units cancelled	**–**	(2,384)	–
Units matured	**(129,852)**	(209,827)	–
Dividend reinvestment	**13,364**	13,911	10,164
Units at end of year	**295,428**	267,616	328,716

Of the PSUs outstanding at December 31, 2008, 146,444 units have a performance period ending December 31, 2009 and 148,984 units have a performance period ending December 31, 2010. The total intrinsic value of PSUs outstanding at December 31, 2008 is $21.0 million (2007 – $10.7 million; 2006 – $12.7 million).

RESTRICTED STOCK UNITS

Enbridge has a RSU plan where cash awards are paid to certain non-executive employees of the Company following a thirty-five month maturity period. RSU holders receive cash equal to the Company's weighted average share price multiplied by the units outstanding on the maturity date. Compensation expense recorded for the year ended December 31, 2008 for RSUs was $15.4 million (2007 – $7.1 million; 2006 – $0.8 million).

Outstanding Restricted Stock Units

December 31,	**2008**	2007	2006
Units at beginning of year	**456,621**	183,253	–
Units granted	**418,700**	276,875	181,882
Units cancelled	**(23,352)**	(18,627)	–
Units matured	**(179,940)**	–	–
Dividend reinvestment	**28,005**	15,120	1,371
Units at end of year	**700,034**	456,621	183,253

The total intrinsic value of RSUs outstanding at December 31, 2008 is $29.4 million (2007 – $18.3 million; 2006 – $7.7 million).

As of December 31, 2008, unrecognized compensation expense related to non-vested units granted under the PSU and RSU plans was $27.8 million, expected to be recognized over a period of 1.7 years.

20. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME / (LOSS)

(millions of Canadian dollars)	Cash Flow Hedges	Equity Investees	Non-Controlling Interests	Cumulative Translation Adjustment	Net Investment Hedges	Total
Balance at January 1, 2006	–	–	–	(486.7)	428.1	(58.6)
Tax impact	–	–	–	–	(113.2)	(113.2)
	–	–	–	(486.7)	314.9	(171.8)
Changes during the period	–	–	–	87.6	(49.0)	38.6
Tax impact	–	–	–	–	(2.6)	(2.6)
	–	–	–	87.6	(51.6)	36.0
Balance at December 31, 2006	–	–	–	(399.1)	263.3	(135.8)
Adjustment on adoption *(Note 2)*	79.4	(57.3)	26.3	–	–	48.4
Tax impact	(20.3)	20.1	–	–	–	(0.2)
	59.1	(37.2)	26.3	–	–	48.2
Changes during the period	94.8	(29.2)	4.9	(447.1)	193.9	(182.7)
Tax impact	(5.1)	9.4	–	–	(19.0)	(14.7)
	89.7	(19.8)	4.9	(447.1)	174.9	(197.4)
Balance at December 31, 2007	148.8	(57.0)	31.2	(846.2)	438.2	(285.0)
Changes during the period	**(175.8)**	**78.5**	**(19.6)**	**576.8**	**(179.8)**	**280.1**
Tax impact	**47.1**	**(29.3)**	**–**	**–**	**19.9**	**37.7**
	(128.7)	**49.2**	**(19.6)**	**576.8**	**(159.9)**	**317.8**
Balance at December 31, 2008	**20.1**	**(7.8)**	**11.6**	**(269.4)**	**278.3**	**32.8**

21. RISK MANAGEMENT

MARKET PRICE RISK

The Company's earnings are subject to movements in interest rates, foreign exchange rates and commodity prices (collectively, market price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

Earnings at Risk (EaR) is the principal risk management metric used to quantify market price risk at Enbridge. EaR is an objective, statistically derived risk metric that measures, with a 97.5% level of confidence, the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period. The Company's policy is to target a maximum EaR of 5% of earnings.

The Company calculates EaR using Monte Carlo simulation to produce projections of earnings using a randomly generated series of forecasted market prices and Enbridge's current market exposures. Historical statistical distributions of market prices and the correlation among those market prices are used to generate an entire probability distribution of possible deviations from forecast earnings. The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

COMMODITY PRICE RISK

The Company is exposed to gains or losses due to changes in the market price of commodities. The Company may use natural gas, power, crude oil and natural gas liquids swaps, collars or options to manage the value of variable price exposures that arise from commodity usage, storage, transportation and supply agreements.

Earnings and OCI impacts from unrealized changes in the commodity risk management instruments mentioned above are driven by revaluation of these instruments at the balance sheet date. Sensitivities are based on the Company's estimate of a reasonably possible change in the price of the underlying commodity and each commodity sensitivity analysis has been calculated independently of each other. For example, increasing the price of crude oil assumes that the price of gas remains constant and that only instruments impacted directly by an increase in the price of crude oil

are affected. The impact of various price increases to commodities at December 31, 2008 would have had the following impact on earnings:

Unit	Crude *(BBL)*	NGL *(gallons)*	Gas *(MMBTU)*	Power *(MWh)*	Fractionation Margins *(gallon)*
Increase per unit	$10.00	$0.25	$1.00	$5.00	US$0.10
(millions of Canadian dollars)					
After-tax impact					
Earnings	**(21.4)**	**(0.1)**	**4.1**	**(0.3)**	**(1.5)**
OCI	**(3.0)**	**(7.4)**	**16.8**	**(0.5)**	**(2.2)**

FOREIGN EXCHANGE RISK

The Company is exposed to both transaction and translation risk due to the volatility of foreign currency exchange rates. The Company has exposure to foreign currency exchange rates, primarily arising from its U.S. dollar denominated investments and, to a lesser extent, its monetary assets and liabilities denominated in this currency.

The carrying values of these assets and liabilities as well as the comprehensive income and earnings derived from them, are subject to foreign exchange rate fluctuation. The Company uses par forward contracts and cross currency swaps to manage a portion of the foreign exchange exposure related to changes in the carrying values, cashflows and earnings of its U.S. dollar denominated investments. The Company uses some of its U.S. dollar denominated debt to hedge the carrying values of certain equity investments. In addition, the Company uses short and long-term foreign exchange forward contracts to manage exposure related to foreign currency denominated receivables, payables and long-term debt.

The Canadian dollar carrying values of the Company's equity investments and monetary assets and liabilities denominated in U.S. dollars at December 31, 2008 are summarized below.

	Assets/ (Liabilities)
(millions of Canadian dollars)	
Net Working Capital	**(223.3)**
Equity Investments	**1,939.7**
Long-Term Debt	**(2,112.3)**

The impact of a $0.05 strengthening of the Canadian dollar relative to the US dollar at December 31, 2008, would have resulted in a $58.4 million increase to earnings and a $19.4 million increase to OCI, due to the revaluation of currency derivatives. Under Section 3862 of the CICA Handbook, the calculation of sensitivity to foreign exchange risk is limited to financial instruments denominated in currencies other than the functional currency in which they are measured and transacted. The sensitivity to changes in foreign exchange rates at the balance sheet date is primarily driven by changes in the fair value of derivative instruments. The $0.05 increase in exchange rates is presumed to have caused a parallel shift in the forward exchange rates used to value financial derivatives maturing in future periods.

INTEREST RATE RISK

The Company is exposed to cashflow and revaluation risk due to the volatility of interest rates. Cash flows are impacted by changes in market interest rates on variable rate debt (primarily commercial paper). Floating to fixed interest rate swaps, collars and forward rate agreements are used to mitigate cash flow volatility due to future interest rate fluctuation. The Company is also exposed to cash flow interest rate risk on fluctuations in market interest rates ahead of anticipated fixed rate debt issuances. The Company may enter into interest rate derivatives such as bond forwards and treasury locks to fix a portion of the interest payments of these future debt issuances. The Company monitors its fixed and variable rate debt instruments, targeting a debt portfolio mix of up to 25% floating rate debt as a percentage of total debt outstanding. Fixed to floating swaps are also used from time to time to manage this position and optimize the Company's debt portfolio. The fair value of existing fixed rate long-term debt is also impacted by changes in market interest rates. The Company does not typically manage the fair value risk of its debt instruments.

A 1.0% increase in interest rates would have caused a $13.7 million increase in OCI at December 31, 2008 due to the revaluation of interest rate derivatives, all of which are designated hedging instruments in cash flow hedging relationships. The sensitivity has been calculated assuming a 1.0% shift in interest rates across the yield curve.

EQUITY PRICE RISK

Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock based compensation, RSUs *(Note 19)*.

Due to revaluation of the equity derivative contracts at December 31, 2008, the impact of a $4 increase in the Company's share price would have been a $0.9 million increase in earnings and a $1.1 million increase in OCI.

SUMMARY OF DERIVATIVE INSTRUMENTS USED FOR RISK MANAGEMENT

The current portion of derivative assets or liabilities is included in Accounts Receivable and Other or Accounts Payable and Other, while the long-term portion is included in Deferred Amounts and Other Assets or Other Long-Term Liabilities.

Total Derivative Instruments

	2008			2007		
December 31,	Notional Principal or Quantity	Derivative Asset/ (Liability)	Maturity	Notional Principal or Quantity	Derivative Asset/ (Liability)	Maturity
(millions of Canadian dollars unless otherwise noted)						
Foreign exchange						
U.S. cross currency swaps	**138.0**	**26.1**	2013-2022	138.0	46.7	2013-2022
U.S. Forwards *(cumulative exchange amounts)*	**3,943.6**	**269.5**	2009-2022	2,608.0	226.3	2008-2022
Interest rates						
Interest rate swaps/collars	**1,164.4**	**(33.0)**	2009-2029	1,117.0	(8.6)	2008-2029
Equity price						
Forwards *(millions of shares)*	**0.7**	**(4.8)**	2009-2010	–	–	–
Energy commodities						
Energy commodity *(bcf)*	**529.9**	**18.6**	2009-2010	452.9	(43.5)	2008-2010
Power *(MW/H)*	**57.0**	**15.8**	2009-2024	57.0	20.6	2008-2024

The fair value of derivative instruments has been estimated using period end market information. This market information includes observable inputs such as published market prices for commodities, interest rate yield curves and foreign exchange rates. When possible, financial instruments are valued using quoted market prices.

Derivative Instruments used as Cash Flow Hedges

	2008			2007		
December 31,	Notional Principal or Quantity	Derivative Asset/ (Liability)	Maturity	Notional Principal or Quantity	Derivative Asset/ (Liability)	Maturity
(millions of Canadian dollars unless otherwise noted)						
Foreign exchange						
U.S. cross currency swaps	**138.0**	**26.1**	2013-2022	138.0	46.7	2013-2022
Forwards *(cumulative exchange amounts)*	**1,661.9**	**164.4**	2009-2022	1,761.4	138.1	2008-2022
Interest rates						
Interest rate swaps/collars	**1,164.4**	**(33.0)**	2009-2029	1,117.0	(8.6)	2008-2029
Equity price						
Forwards *(millions of shares)*	**0.7**	**(2.8)**	2009-2010	–	–	–
Energy commodities						
Energy commodity *(bcf)*	**26.4**	**(58.3)**	2009-2010	43.6	3.2	2008-2010
Power *(MW/H)*	**2.0**	**(3.4)**	2009-2024	2.0	(2.1)	2008-2017

The Company estimates that $48.4 million of accumulated other comprehensive loss related to cash flow hedges will be reclassified to earnings in the next 12 months.

Derivative and Other Financial Instruments used as Net Investment Hedges

December 31,	2008 Notional Principal or Quantity	2008 Derivative Asset/ (Liability)	2008 Maturity	2007 Notional Principal or Quantity	2007 Derivative Asset/ (Liability)	2007 Maturity
(millions of Canadian dollars)						
Foreign exchange						
Forwards *(cumulative exchange amounts)*	**441.9**	**71.0**	2014-2020	749.9	187.0	2013-2020

The Company has also designated a US$300 million medium-term note and US$189.4 million of commercial paper as hedges of certain U.S. dollar investments.

During the year, the Company terminated certain par forward currency exchange instruments for proceeds of $48.2 million. These instruments hedged US$162.4 million of the Company's U.S. dollar long-term investments and were accounted for as net investment hedges with the fair value recorded as long-term assets on the balance sheet with an equal and offsetting amount recorded in AOCI. No gain or loss related to the terminations was recorded in the Company's earnings.

FAIR VALUE HEDGES

As at December 31, 2008, the Company did not have any outstanding fair value hedges.

UNREALIZED GAINS AND LOSSES ON NON-QUALIFYING DERIVATIVES

The Company does not use derivative instruments for speculative purposes; however, if a derivative instrument is not an effective hedge for accounting purposes or is not designated as a hedging item, changes in the fair value are recorded in current period earnings. For the year ended December 31, 2008, the Company had an after tax unrealized gain of $75.3 million (2007 – $32.3 million loss) related to non-qualifying derivatives. Realized losses on non-qualifying derivative instruments for the year ended December 31, 2008 were $35.6 million (2007 – $9.9 million), after tax.

The Company's regulated Liquids Pipelines segment uses a fixed price contract and related financial instrument to manage floating power costs. The Company recognizes the fair value of the fixed price contract, the fair value of the financial instrument and a regulatory liability that will be recognized over the life of the fixed price contract. At December 31, 2008, the Company recognized a liability of $3.4 million for unrealized financial instrument losses, an asset of $24.3 million related to the fixed price power contract and a regulatory liability of $20.9 million.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees (see Notes 29 and 30), as they become due. In order to manage this risk, the Company forecasts the cash requirements over the near and long term to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and longer term debt which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with the securities regulators, which enables, subject to market conditions, ready access to either the Canadian or U.S. public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities (see Note 15), with a diversified group of banks and institutions, which would enable the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities and expects to be in compliance throughout 2009. Therefore, the entire credit facility is available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facility. The Company expects to generate sufficient cash from operations and commercial paper issuances and draws under its committed credit facilities to fund liabilities as they become due, finance planned investing activity and pay common share dividends throughout the year. Additional liquidity, if necessary, is expected to be available through access to the capital markets.

Maturities of Financial Liabilities

The Company generally has no financial liabilities maturing beyond one year with the exception of its long-term debt *(Notes 15 and 16)*.

CREDIT RISK

Entering into derivative financial instruments can result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. In light of economic conditions at the balance sheet date, the Company has placed increased scrutiny around its credit exposures with significant financial institutions. The Company enters into risk management transactions only with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits, contractual and collateral requirements, frequent assessment of counterparty credit ratings and netting arrangements. At December 31, 2008, the Company has a maximum exposure to credit risk of $388.5 million related to its derivative counterparties.

Credit risk also arises from trade and other long-term receivables, which is mitigated through credit exposure limits, contractual and collateral requirements, assessment of credit ratings and netting arrangements. Credit risk in the Gas Distribution and Services segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers, and in select cases has recently tightened credit terms including obtaining additional security, to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in the financial instruments summary table below.

The change in the allowance for doubtful accounts in respect of accounts receivable is detailed below.

Year ended December 31,	**2008**	2007
(millions of Canadian dollars)		
Balance at beginning of year	**(55.4)**	(50.6)
Additional allowance	**(37.1)**	(23.6)
Amounts used	**22.3**	18.6
Amounts reversed	**1.2**	0.2
Balance at end of year	**(69.0)**	(55.4)

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivables in EGD are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate.

Net derivative asset maturities for the years ending December 31, 2009 though 2013 and thereafter are $6.8 million, $15.1 million, $28.7 million, $30.1 million, $36.8 million and $151.2 million.

22. FAIR VALUE OF FINANCIAL INSTRUMENTS

	December 31, 2008		December 31, 2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
(millions of Canadian dollars)				
Financial Assets				
Cash and cash equivalents	**541.7**	**541.7**	166.7	166.7
Accounts receivable and other	**2,074.0**	**2,074.0**	2,095.4	2,095.4
Available for sale [1]	**81.1**	**n/a**	75.0	n/a
Held to maturity [2]	**404.7**	**359.2**	404.7	379.5
Current derivative assets [3]	**71.6**	**71.6**	79.5	79.5
Long-term derivative assets [3]	**316.9**	**316.9**	368.5	368.5
Long-term notes receivable	**166.9**	**132.6**	133.8	133.0
Financial Liabilities				
Accounts payable and other deferred amounts	**2,100.8**	**2,100.8**	2,095.5	2,095.5
Short-term borrowings	**874.6**	**874.6**	545.6	545.6
Long-term debt [4]	**13,323.9**	**12,786.0**	10,509.1	10,489.0
Current derivative liabilities [3]	**49.4**	**95.8**	82.4	82.4
Long-term derivative liabilities [3]	**46.5**	**46.5**	64.0	64.0

1 *Available for sale investments do not trade on an actively quoted market and no fair value disclosure is available.*

2 *Held to maturity investments include instruments denominated in U.S. dollars that have a fair value less than carrying value due to exchange rate fluctuations. This decline in fair value is considered temporary.*

3 *Derivative assets and liabilities include those derivatives used in hedging relationships and non-qualifying derivatives.*

4 *Long-term debt includes non-recourse debt and excludes transaction costs.*

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such prices are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs. The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents and short-term borrowings approximates their carrying value due to their short-term maturities.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure.

The fair value of other financial assets and liabilities other than derivatives approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities are due solely to fluctuations in interest rates and commodity prices as well as time value.

FAIR VALUE OF DERIVATIVES

The Company categorizes its derivative assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

This category includes assets and liabilities measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for an asset or liability is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 instruments consist primarily of exchange-traded derivative instruments used to mitigate the risk of crude oil price fluctuations in its Liquids Pipelines and Energy Services businesses.

Level 2

This category includes valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivative instruments in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted

forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative instrument. Instruments valued using Level 2 inputs include non-exchange traded derivatives such as over the counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps and options for which observable inputs can be obtained. These instruments are used primarily in the Company's Energy Services businesses and the Corporate segment.

Level 3

This category includes valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the instruments' fair value. Generally, Level 3 valuations are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked to industry standards, to determine fair value for these contracts based on extrapolation of observable future prices and rates. Instruments valued using Level 3 inputs include long dated derivative power, NGL and natural gas contracts in its Liquids Pipelines and Energy Services businesses.

When possible the estimated fair value is based on quoted market prices, and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company's uses standard valuation techniques to calculate fair value. These methods include discounted mark to market for forwards, futures and swaps and Black-Scholes for options. Primary inputs to these techniques include observable market prices (interest, foreign exchange and commodity) and volatility, depending on the type of derivative and nature of the underlying risk. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible the Company uses observable inputs.

The fair value hierarchy of financial assets and liabilities accounted for at fair value on a recurring basis at December 31, 2008 are as follows.

	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets:				
Current derivative assets	**422.2**	**266.4**	**802.3**	**1,490.4**
Long-term derivative assets	**161.8**	**2,105.1**	**256.4**	**2,523.3**
Financial liabilities:				
Current derivative liabilities	**430.8**	**263.4**	**766.2**	**1,460.4**
Long-term derivative liabilities	**183.9**	**1,831.0**	**246.6**	**2,261.5**

Changes in the fair value of $135.1 million classified as Level 3 in the fair value hierarchy during the year ended December 31, 2008, were as follows:

Fair value measurements using significant unobservable inputs (Level 3)

	2008
(millions of Canadian dollars)	
Balance at beginning of year	**(89.2)**
Total gains/(losses), realized and unrealized	
Included in earnings	**52.0**
Included in other comprehensive income	**2.4**
Purchases, issuances and settlements	**80.7**
Balance at end of year	**45.9**

Unrealized gains and losses are reported within commodity costs and other investment income.

23. CAPITAL DISCLOSURES

The Company defines capital as shareholders' equity (excluding AOCI and reciprocal shareholdings), long-term debt (excluding non-recourse debt and transaction costs), short-term borrowings and non-controlling interests less cash and cash equivalents (excluding cash and cash equivalents from joint ventures and other interests not exclusively controlled by the Company). Non-recourse debt, including debt consolidated proportionately from joint venture interests, is excluded from the Company's definition of capital as it is not controlled or managed exclusively by the Company.

The Company's capital is calculated as follows:

December 31, *(millions of Canadian dollars)*	**2008**	2007
Short-term borrowings	**874.6**	545.6
Long-term debt (includes current portion)	**10,794.4**	8,393.9
Non-controlling interests	**797.4**	650.5
Shareholders' equity	**6,740.3**	5,714.5
Cash and cash equivalents	**(469.3)**	(115.9)
	18,737.4	15,188.6

The Company's objectives when managing capital are to maintain flexibility among:

- enabling its businesses to operate at the highest efficiency;
- providing liquidity for growth opportunities; and
- providing acceptable returns to shareholders.

These objectives are primarily met through maintenance of an investment grade credit rating, which provides access to lower cost capital. Capital is available generally through the issuance of both short and long-term debt, and equity.

The Company monitors and manages its debt to debt plus equity ratio (excluding non-recourse debt), with a target range of 60% to 70%, to meet its capital management objectives. The debt to capitalization ratio at December 31, 2008, including short-term borrowings but excluding non-recourse short and long-term debt, was 63.1%, compared with 62.7% at the end of 2007.

The Company must adhere to covenants in its credit facilities that are used to backstop its commercial paper program. These covenants include maintaining a minimum Consolidated Shareholders' Equity balance of $1 billion or greater and a debt to Unconsolidated Shareholders' Equity of less than 1.5. As at December 31, 2008, the Company was in compliance with these covenants.

Under terms of the Company's Trust Indenture, in order to continue to issue long-term debt, the Company must maintain a ratio of Consolidated Funded Obligations (essentially all debt except non-recourse debt) to Total Consolidated Capitalization of less than 75%. Total Consolidated Capitalization consists of shareholders' equity, long-term debt, non-controlling interests and future income tax. As at December 31, 2008, the Company was in compliance with this covenant.

24. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	2008	2007	2006
(millions of Canadian dollars)			
Earnings before income taxes	**1,836.6**	916.3	814.6
Combined statutory income tax rate	**31.3%**	33.9%	34.4%
Income taxes at statutory rate	**574.9**	310.6	280.2
Increase/(decrease) resulting from:			
Tax rates and legislated tax changes	**(11.4)**	(62.8)	(63.0)
Future income taxes related to regulated operations	**(15.3)**	(5.8)	(10.5)
Non-taxable items, net	**2.6**	(18.5)	(21.4)
Higher/(lower) foreign tax rates	**3.6**	(6.4)	(6.7)
CLH disposition	**(82.2)**	–	–
Other	**36.7**	(7.9)	13.7
Income Taxes	**508.9**	209.2	192.3
Effective income tax rate	**27.7%**	22.8%	23.6%

In 2008, income taxes paid amounted to $161.2 million (2007 – $226.2 million; 2006 – $182.6 million).

COMPONENTS OF FUTURE INCOME TAXES

December 31,	2008	2007
(millions of Canadian dollars)		
Net Future Income Tax Liabilities/(Assets)		
Differences in accounting and tax bases of property, plant and equipment	**790.3**	608.6
Differences in accounting and tax bases of investments	**452.3**	337.0
Other comprehensive income	**(28.2)**	42.4
Loss carryforwards	**(150.6)**	(222.0)
Other	**48.8**	22.9
Total Net Future Income Tax Liability	**1,112.6**	788.9

Net future income tax liability of $1,112.6 million (2007 – $788.9 million) includes future income tax liabilities of $1,290.8 million (2007 – $975.6 million) net of future tax assets of $178.2 million (2007 – $186.7 million).

At December 31, 2008, the Company has recognized the benefit of unused tax loss carryforwards of $451.6 million (2007 – $665.1 million). Unused tax loss carryforwards expire as follows: 2011 – $0.1 million; 2012 – $0.7 million; 2013 – $1.3 million; 2014 – $0.1 million; 2015 – $3.8 million and 2021 and beyond – $445.6 million.

GEOGRAPHIC COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31, *(millions of Canadian dollars)*	**2008**	2007	2006
Earnings before income taxes			
Canada	**624.1**	511.1	430.7
United States	**419.0**	210.2	237.8
Other	**793.5**	195.0	146.1
	1,836.6	916.3	814.6
Current income taxes			
Canada	**140.5**	152.7	204.3
United States	**43.3**	11.9	0.1
Other	**67.0**	3.8	8.9
	250.8	168.4	213.3
Future income taxes			
Canada	**92.4**	(36.3)	(112.0)
United States	**165.7**	77.1	91.0
	258.1	40.8	(21.0)
Current and future income taxes	**508.9**	209.2	192.3

25. POST EMPLOYMENT BENEFITS

PENSION PLANS

The Company has three basic pension plans which provide either defined benefit or defined contribution pension benefits, or both to employees of the Company. The Liquids Pipelines and Gas Distribution and Services pension plans provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge U.S. pension plan provides Company funded defined benefit pension benefits for U.S. based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees.

The measurement date used to determine the plan assets and the accrued benefit obligation was September 30, 2008 for the Canadian pension plans and December 31, 2008 for the U.S. pension plan.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Liquids Pipelines	December 31, 2006	December 31, 2009
Enbridge U.S.	December 31, 2007	December 31, 2008
Gas Distribution and Services	December 31, 2006	December 31, 2009

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, pension costs equal amounts required to be contributed by the Company. Pension costs in respect of these plans during the year were $3.9 million (2007 – $3.6 million; 2006 – $3.0 million).

POST-EMPLOYMENT BENEFITS OTHER THAN PENSIONS

Post-employment benefits other than pensions primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	OPEB		Pension Benefits	
	2008	2007	**2008**	2007
(millions of Canadian dollars)				
Change in Accrued Benefit Obligation				
Benefit obligation at beginning of year	**183.4**	193.2	**1,100.4**	1,109.0
Service cost	**5.2**	4.7	**52.4**	43.8
Interest cost	**11.5**	10.1	**64.9**	57.9
Amendments	**–**	–	**(3.5)**	0.1
Employees' contributions	**0.6**	0.4	**–**	–
Actuarial loss/(gain)	**(26.8)**	(10.2)	**(125.0)**	(46.4)
Benefits paid	**(7.3)**	(6.7)	**(45.6)**	(42.2)
Effect of exchange rate changes	**12.7**	(8.1)	**31.7**	(21.8)
Benefit obligation at end of year	**179.3**	183.4	**1,075.3**	1,100.4
Change in Plan Assets				
Fair value of plan assets at beginning of year	**47.8**	50.2	**1,309.9**	1,227.1
Actual return on plan assets	**(11.7)**	1.7	**(179.7)**	104.8
Employer's contributions	**8.2**	8.1	**33.3**	44.1
Employees' contributions	**0.6**	0.4	**–**	–
Benefits paid	**(7.3)**	(6.7)	**(45.6)**	(42.2)
Other	**–**	–	**(1.4)**	(1.5)
Effect of exchange rate changes	**8.2**	(5.9)	**24.8**	(22.4)
Fair value of plan assets at end of year	**45.8**	47.8	**1,141.3**	1,309.9
Funded Status				
Benefit obligation	**(179.3)**	(183.4)	**(1,075.3)**	(1,100.4)
Fair value of plan assets	**45.8**	47.8	**1,141.3**	1,309.9
Overfunded/(Underfunded) status at end of year	**(133.5)**	(135.6)	**66.0**	209.5
Contribution after measurement date	**1.1**	1.0	**1.9**	–
Unamortized prior service cost	**–**	–	**7.4**	12.8
Unamortized transitional obligation/(asset)	**10.8**	12.1	**(15.4)**	(17.6)
Unamortized net loss	**24.6**	32.9	**167.0**	13.5
Net amount recognized at end of year	**(97.0)**	(89.6)	**226.9**	218.2

The amounts recognized include all of the Company's plans; however, the Gas Distribution and Services plans are funded through regulated rates on a cash basis and are not recorded as net pension assets or liabilities. Excluding Gas Distribution and Services plans, the Company's plans using the accrual method provide for a net pension asset of \$73.8 million (2007 – \$72.3 million) and a net OPEB liability of \$21.5 million (2007 – \$18.8 million). The pension asset is recorded on the balance sheet in Deferred Amounts and Other Assets while the pension liability is recorded in Other Long-Term Liabilities, with the current portion for each recorded in working capital accounts.

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	OPEB			Pension Benefits		
Year ended December 31,	**2008**	2007	2006	**2008**	2007	2006
Discount rate	**6.42%**	5.71%	5.37%	**6.59%**	5.65%	5.27%
Average rate of salary increases				**5.00%**	5.00%	5.00%

NET PENSION PLAN AND OPEB COSTS RECOGNIZED

Year ended December 31,	**2008**	2007	2006
(millions of Canadian dollars)			
Benefits earned during the year	**57.6**	52.1	45.7
Interest cost on projected benefit obligations	**76.4**	68.0	64.2
Actual return on plan assets	**191.4**	(106.5)	(80.3)
Difference between actual and expected return on plan assets	**(287.7)**	19.9	(3.4)
Amortization of prior service costs	**2.0**	2.0	2.0
Amortization of transitional obligation	**(0.9)**	(0.9)	(0.8)
Amortization of actuarial loss	**4.9**	13.9	15.3
Amount charged to EEP	**(10.8)**	(11.3)	(10.5)
Pension and OPEB cost recognized	**32.9**	37.2	32.2

The table reflects the pension and OPEB cost for all of the Company's benefit plans on an accrual basis. Using the cash basis for Gas Distribution and Services rate regulated plans and the accrual method for all other plans, the Company's pension cost was $27.4 million (2007 – $23.4 million; 2006 – $20.1 million), and its OPEB cost was $6.8 million for 2008 (2007 – $6.9 million; 2006 – $7.0 million).

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	OPEB			Pension Benefits		
Year ended December 31,	**2008**	2007	2006	**2008**	2007	2006
Discount rate	**5.71%**	5.37%	5.30%	**5.65%**	5.27%	5.24%
Average rate of return on pension plan assets	**6.00%**	4.50%	4.50%	**7.30%**	7.31%	7.31%
Average rate of salary increases				**5.00%**	5.00%	4.44%

MEDICAL COST TREND RATES

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	10%	5%	2016
Other Medical and Dental	5%	5%	2008
U.S. Plan	10%	5%	2013

A one percent increase in the assumed medical and dental care trend rate would result in an increase of $25.0 million in the accumulated post-employment benefit obligations and an increase of $2.3 million in benefit and interest costs. A one percent decrease in the assumed medical and dental care trend rate would result in a decrease of $20.3 million in the accumulated post-employment benefit obligations and a decrease of $1.8 million in benefit and interest costs.

MAJOR CATEGORIES OF PLAN ASSETS

	OPEB			Pension Benefits		
	2008		2007	2008		2007
Year ended December 31,	Actual	Amount	Actual	Actual	Amount	Actual
(millions of Canadian dollars)						
Equity securities	–	–	–	**57.3%**	**653.5**	60.7%
Fixed income securities	**84.2%**	**38.6**	85.4%	**35.1%**	**400.5**	33.5%
Other	**15.8%**	**7.2**	14.6%	**7.6%**	**87.3**	5.8%
Total Assets	**100%**	**45.8**	100%	**100%**	**1,141.3**	100%

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

The Company manages the investment risk of its pension funds by setting a long term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plans; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

The target asset mix for each of the pension plans are as follows:

	Enbridge Inc. and Affiliates	Enbridge Gas Distribution Inc. and Affiliates	Enbridge (U.S.) Inc.
Equity securities	62.5%	52.5%	57.5%
Fixed income securities	32.5%	42.5%	37.5%
Other	5%	5%	5%

EXPECTED RATE OF RETURN ON PLAN ASSETS

	OPEB		Pension Benefits	
Year ended December 31,	**2008**	2007	**2008**	2007
Canadian Plans	**6.00%**	4.50%	**7.25%**	7.25%
U.S. Plan	**6.00%**	4.50%	**7.75%**	7.75%

PLAN CONTRIBUTIONS BY THE COMPANY

	OPEB		Pension Benefits	
Year ended December 31,	**2008**	2007	**2008**	2007
(millions of Canadian dollars)				
Total contributions	**8.2**	8.1	**33.3**	44.1
Contributions expected to be paid in 2009	**10.1**		**48.4**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2009	2010	2011	2012	2013	2014-2018
(millions of dollars)						
Expected future benefit payments	54.8	57.8	60.5	63.7	67.1	395.8

26. OTHER INVESTMENT INCOME

Year ended December 31,	2008	2007	2006
(millions of Canadian dollars)			
Interest income on affiliate loans	**33.5**	32.7	29.3
Gain on reduction of EEP ownership interest	**12.5**	33.9	–
Noverco preferred dividends income	**16.1**	15.8	15.6
OCENSA investment income	**23.4**	24.7	26.8
Net foreign currency gains	**43.0**	26.2	13.3
Allowance for equity funds used during construction (AEDC)	**58.9**	15.1	1.5
Hurricane insurance recoveries	**–**	14.6	6.0
Other	**15.3**	32.1	15.3
	202.7	195.1	107.8

27. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	2008	2007	2006
(millions of Canadian dollars)			
Accounts receivable and other	**201.6**	(502.1)	3.9
Inventory	**(135.3)**	159.5	134.1
Deferred amounts and other assets	**95.5**	(134.6)	(67.3)
Accounts payable and other [1]	**(181.4)**	503.8	43.5
Interest payable	**9.3**	(5.9)	12.5
	(10.3)	20.7	126.7

1 Changes in construction payable are included in investing activities.

28. RELATED PARTY TRANSACTIONS

EEP does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, are:

Year ended December 31,	2008	2007	2006
(millions of Canadian dollars)			
EEP	**301.9**	267.1	244.9
Vector Pipeline	**5.8**	4.8	4.1
	307.7	271.9	249.0

At December 31, 2008, the Company has accounts receivable from EEP of $40.9 million (2007 – $32.4 million).

The Company has provided EEP with an unsecured revolving credit agreement. The credit facility provides for a maximum principle amount of US$500.0 million for a three-year term maturing in December 2010. At December 31, 2008 and 2007, there were no amounts outstanding on this facility.

EGD, a subsidiary of the Company, has contracts for gas transportation services from Alliance Pipeline and Vector Pipeline. EGD is charged market prices for these services:

Year ended December 31,	2008	2007	2006
(millions of Canadian dollars)			
Alliance Pipeline Canada	**23.6**	21.3	23.6
Alliance Pipeline US	**17.1**	15.1	14.1
Vector Pipeline	**27.0**	25.0	27.3
	67.7	61.4	65.0

CustomerWorks Limited Partnership (CustomerWorks), a joint venture, provided customer care services to EGD under an agreement having a five-year term which expired in 2007 and was not renewed. EGD was charged market prices for these services. CustomerWorks also rented an automated billing system from Enbridge Commercial Services Inc. (ECS), a subsidiary of the Company. Amounts charged by/(to) CustomerWorks are as follows:

Year ended December 31,	**2008**	2007	2006
(millions of Canadian dollars)			
EGD	**–**	26.3	108.5
ECS	**(2.0)**	(1.8)	(8.1)
	(2.0)	24.5	100.4

Enbridge Gas Services (US) Inc., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. Amounts paid/(recovered) are as follows:

Year ended December 31,	**2008**	2007	2006
(millions of Canadian dollars)			
Purchases	**52.1**	43.5	29.2
Sales	**(7.5)**	(4.1)	(6.3)
	44.6	39.4	22.9

Enbridge Gas Services Inc., a subsidiary of the Company, has transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada and Vector Pipeline. Amounts paid are as follows:

Year ended December 31,	**2008**	2007	2006
(millions of Canadian dollars)			
Alliance Pipeline Canada	**9.3**	8.5	8.3
Vector Pipeline	**0.6**	0.6	0.6
	9.9	9.1	8.9

Enbridge Gas Services (US) Inc., a subsidiary of the Company, has transportation commitments, measured at market value, through 2015 on Alliance Pipeline US and Vector Pipeline. Amounts paid are as follows:

Year ended December 31,	**2008**	2007	2006
(millions of Canadian dollars)			
Alliance Pipeline US	**7.0**	6.6	6.9
Vector Pipeline	**15.4**	15.6	16.5
	22.4	22.2	23.4

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP as follows:

Year ended December 31,	**2008**	2007	2006
(millions of Canadian dollars)			
Purchases	**24.5**	4.6	17.0
Sales	**(9.4)**	(5.5)	(6.7)
	15.1	(0.9)	10.3

RECEIVABLE FROM AFFILIATE

The receivable from affiliate of $159.2 million (2007 – $128.5 million), included in Deferred Amounts and Other Assets, initially resulted from the sale of Enbridge Midcoast Energy to EEP. During 2007, the original loan receivable was repaid and a new loan was entered into. The loan, denominated in U.S. dollars, bears interest at 8.4% and matures in 2017. Interest income related to the note was $11.6 million, $10.0 million and $11.8 million, in 2008, 2007 and 2006, respectively.

TRANSFER OF LINE PIPE

The Company and EEP, an equity investee, regularly collaborate on construction projects. Examples of such projects include the Southern Access and Alberta Clipper projects where the Company is constructing the Canadian portion of the projects and EEP is constructing the United States portion. In August 2008, the Company transferred $22.5 million, measured at market value, of 36 inch diameter line pipe to EEP for use in constructing the Alberta Clipper project. The line pipe was initially obtained by the Company for use in constructing the Southern Access Extension, which has been delayed due to a prolonged regulatory process.

29. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has significant signed contracts for the purchase of services, pipe and other materials totaling $1,986.0 million, to be used in the construction of several Liquids Pipelines projects including Southern Lights Pipeline, Alberta Clipper Project, Southern Access Expansion, Hardisty Terminal, Fort Hills Pipeline and Line 4 Extension and certain other administrative services.

ENBRIDGE GAS DISTRIBUTION INC.

Bloor Street Incident

The Company had been charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges laid against the Company were dismissed by the Ontario Court of Justice. The decision has been appealed by the Crown to the Ontario Superior Court of Justice. The appeal is scheduled to be heard by the Court during 2009. The maximum possible fine upon conviction would not result in any material financial impact on the Company.

The Company has also been named as a defendant in a number of civil actions related to the explosion. All significant civil actions have been settled without any material financial impact on the Company. A Coroner's Inquest in connection with the explosion is also possible.

GST Overpayment

In December 2007, EGD discovered that it had remitted excess GST to the Canada Revenue Agency (CRA). In respect of certain months within the 2003 to 2005 calendar year periods, the amount of such overpayment is approximately $40 million and is included in accounts receivable. The Company expects that it will recover the overpayment from the CRA during 2009.

Harper Gardens Incident

On February 14, 2007, an explosion and fire occurred at a residence on Harper Gardens in Toronto. The home was destroyed and a resident of the home was killed. A natural gas contractor working in the home at the time of the explosion was seriously injured. Several public authorities commenced investigations in connection with the incident. The Company has also been named as a defendant in civil actions related to the incident, but does not expect these actions to result in any material financial impact.

Remediation of Discontinued Manufactured Gas Plant Sites

EGD may incur future costs due to claims relating to alleged coal tar contamination at or near former manufactured gas plant (MGP) sites. In October 2002, a claim was filed for $55.0 million in damages relating to a certain MGP site. EGD filed a statement of defence in June 2003 denying liability. Although the Company believes that it has a valid defence to this claim, certain risks exist. The probable overall cost cannot be determined at this time due to uncertainty about the presence and extent of damage in addition to the potential alternative remediation approaches which vary in cost. EGD expects that costs, if any, not recovered through insurance may be recovered through rates. As such, EGD does not believe the outcome will have any material financial impact.

ENBRIDGE ENERGY COMPANY, INC.

Enbridge Energy Company, Inc. (EEC), a subsidiary of the Company and the general partner of EEP, is the former owner of Enbridge Midcoast Energy Inc. (Midcoast). The IRS challenged Midcoast's tax treatment of its 1999 acquisition of several partnerships that owned a natural gas pipeline system in Kansas (these assets were sold to EEP in 2002 and subsequently sold by EEP in 2007). In March 2008, an unfavourable court decision was received sustaining the IRS position, decreasing the U.S. tax basis for the pipeline assets. The Company's earnings for 2008 reflected a decrease of $32.2 million in consideration of the adverse court decision which, when combined with

amounts previously recorded, provides fully for the liability. Given loss carryforwards in EEC prior to the decision, the cash tax impact of the decision was not significant. The Company continues to believe the tax treatment of the acquisition and the related tax deductions claimed were appropriate and has appealed the decision.

OTHER TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATION

The Company and its subsidiaries are subject to various other legal actions and proceedings which arise in the normal course of business. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

30. GUARANTEES

EEC, as the general partner of EEP, has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

In addition, in the event of default, EEC is subject to recourse with respect to US$93.0 million of EEP's long-term debt at December 31, 2008 (2007 – US$124.0 million).

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties. The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments under these indemnification provisions. While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Examples where such indemnification obligations have been issued include:

Sale Agreements for Assets or Businesses:

- breaches of representations, warranties or covenants;
- loss or damages to property;
- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements:

- breaches of representations, warranties or covenants;
- changes in laws;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, the Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

31. SUBSEQUENT EVENT

In January, 2009, the Company secured incremental credit of $225 million from its banking group for an existing credit facility established in December 2008. The new commitments provide additional liquidity and increase the total credit facilities to $8.8 billion.

32. UNITED STATES ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP. The effects of significant differences between Canadian GAAP and U.S. GAAP for the Company are described below.

EARNINGS AND COMPREHENSIVE INCOME

Year ended December 31,	**2008**	2007	2006
(millions of Canadian dollars, except per share amounts)			
Earnings under Canadian and U.S. GAAP Applicable to Common Shareholders	**1,320.8**	700.2	615.4
Earnings under Canadian and U.S. GAAP	**1,327.7**	707.1	622.3
Other comprehensive income/(loss) under Canadian GAAP	**317.8**	(197.4)	36.0
Underfunded pension adjustment (net of tax) [4]	**(56.6)**	23.3	–
Unrealized net gain/(loss) on cash flow hedges	**–**	–	(64.2)
Comprehensive income under U.S. GAAP	**1,588.9**	533.0	594.1
Earnings per common share under U.S. GAAP	**3.67**	1.97	1.81
Diluted earnings per common share under U.S. GAAP	**3.64**	1.95	1.79

FINANCIAL POSITION

December 31,	2008 Canada	2008 United States	2007 Canada	2007 United States
(millions of Canadian dollars)				
Assets				
Cash and cash equivalents [2, 5]	**541.7**	**961.0**	166.7	214.4
Accounts receivable and other [2, 3, 5]	**2,322.5**	**3,174.8**	2,388.7	3,118.4
Inventory [2, 5]	**844.7**	**911.3**	709.4	817.3
	3,708.9	**5,047.1**	3,264.8	4,150.1
Property, plant and equipment, net [2, 5]	**16,389.6**	**24,738.0**	12,597.6	17,999.4
Long-term investments [2, 5]	**2,491.8**	**412.2**	2,076.3	1,253.1
Deferred amounts and other assets [1, 2, 3, 4, 5]	**1,318.4**	**2,079.5**	1,182.0	1,653.5
Intangible assets [5]	**225.3**	**333.9**	212.0	302.4
Goodwill [5]	**389.2**	**807.7**	388.0	725.1
Future income taxes [1, 5]	**178.2**	**178.2**	186.7	187.3
	24,701.4	**33,596.6**	19,907.4	26,270.9
Liabilities and Shareholders' Equity				
Short-term borrowings	**874.6**	**874.6**	545.6	545.5
Accounts payable and other [2, 3, 5]	**2,411.5**	**3,202.7**	2,213.8	3,195.1
Interest payable [5]	**101.9**	**143.6**	89.1	109.8
Current maturities and short-term debt [5]	**533.8**	**533.8**	605.2	632.7
Current portion of non-recourse debt [2, 5]	**184.7**	**706.0**	61.1	60.9
	4,106.5	**5,460.7**	3,514.8	4,544.0
Long-term debt [3]	**10,154.9**	**10,256.9**	7,729.0	7,771.7
Non-recourse long-term debt [2, 5]	**1,474.0**	**5,447.5**	1,508.4	4,337.2
Other long-term liabilities [2, 4, 5]	**259.0**	**398.6**	253.9	479.2
Future income taxes [1, 2, 3, 4, 5]	**1,290.8**	**2,014.2**	975.6	1,545.7
Non-controlling interests [5]	**797.4**	**3,493.8**	650.5	2,355.2
	18,082.6	**27,071.7**	14,632.2	21,033.0
Shareholders' Equity				
Preferred shares	**125.0**	**125.0**	125.0	125.0
Common shares	**3,194.0**	**3,194.0**	3,026.5	3,026.5
Contributed surplus	**37.9**	**–**	25.7	–
Retained earnings	**3,383.4**	**3,350.5**	2,537.3	2,504.4
Additional paid in capital	**–**	**81.7**	–	69.6
Accumulated other comprehensive loss [3, 4]	**32.8**	**(72.0)**	(285.0)	(333.3)
Reciprocal shareholding	**(154.3)**	**(154.3)**	(154.3)	(154.3)
	6,618.8	**6,524.9**	5,275.2	5,237.9
	24,701.4	**33,596.6**	19,907.4	26,270.9

1 Future Income Taxes
Under U.S. GAAP, deferred income tax liabilities are recorded for rate-regulated operations, which follow the taxes payable method for ratemaking purposes. As these deferred income taxes are expected to be recoverable in future revenues, a corresponding regulatory asset is also recorded. These assets and liabilities are adjusted to reflect changes in enacted income tax rates. At December 31, 2008, a deferred tax liability of $803.3 million (2007 – $572.7 million) is recorded for U.S. GAAP purposes and reflects the difference between the carrying value and the tax basis of property, plant and equipment. Regulated companies following the taxes payable method are not required to record this additional tax liability under Canadian GAAP. For the year ended December 31, 2007, to recover the additional deferred income taxes recorded under U.S. GAAP through the ratemaking process, it would have been necessary to record incremental revenue of $785.6 million.

2 Accounting for Joint Ventures
U.S. GAAP requires the Company's investments in joint ventures to be accounted for using the equity method. However, under an accommodation of the U.S. Securities and Exchange Commission, accounting for jointly controlled investments need not be reconciled from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. Joint ventures in which all owners do not share joint control are reconciled to U.S. GAAP. The different accounting treatment affects only display and classification and not earnings or shareholders' equity.

3 Accumulated Other Comprehensive Loss

Financial instruments are now recognized in Canadian GAAP in substantially the same manner as U.S. GAAP. As a result of the change in Canadian accounting, certain comparative balances have been reclassified for U.S. GAAP purposes, including the recognition of regulated non-financial instruments and offsetting regulatory liabilities as well as OCI from equity investees. In addition, transaction costs arising from the issuance of debt are now recorded net against the related long-term debt. For U.S. GAAP, these transaction costs are reclassified to deferred amounts and other assets.

The only Canadian – U.S. GAAP difference in accumulated other comprehensive loss is the underfunded status of the pension and OPEB plans. The following are the impacts of the underfunded status on OCI in Canadian dollars.

Amounts removed from other comprehensive income (OCI) and recognized as components of the net pension and OPEB costs in the year is as follows:

Year ended December 31,	*2008*	*2007*
(millions of Canadian dollars)		
Prior service cost	*0.5*	*0.5*
Net transitional obligation	*(1.0)*	*(1.0)*
Net loss	*1.6*	*3.1*
	1.1	*2.6*

Amounts accumulated in OCI that have not yet been recognized as a component of net periodic benefit cost is as follows:

Year ended December 31,	*2008*	*2007*
(millions of Canadian dollars)		
Prior service cost	*0.8*	*3.5*
Net transitional obligation	*(5.8)*	*(6.7)*
Net loss	*109.9*	*51.5*
	104.9	*48.3*

Net amounts reflected in OCI for the year are as follows:

Year ended December 31,	*2008*	*2007*
(millions of Canadian dollars)		
Unamortized prior service cost	*(2.8)*	*(0.9)*
Unamortized net transitional obligation	*1.0*	*0.9*
Net loss/(gain)	*58.4*	*(23.3)*
	56.6	*(23.3)*

The Company estimates that approximately $1.2 million related to pension and OPEB plans at December 31, 2008 will be reclassified into earnings in the next twelve months.

	Pension Benefits	*OPEB*
(millions of Canadian dollars)		
Net transitional obligation	*(1.1)*	*0.5*
Prior service costs	*0.2*	*–*
Loss	*1.4*	*0.2*
Reclassification	*0.5*	*0.7*

The after tax amounts recognized in the tables above exclude the Gas Distribution and Services plans since these plans are funded through regulated rates on a cash basis and are not recorded as net pension assets or liabilities.

4 Pension Funding Status

FAS 158, Employers' Accounting for Defined Pension and Other Postretirement Plans, *requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan or OPEB as an asset or liability and to recognize changes in the funded status in the period in which they occur through comprehensive income. FAS 158 adjustments resulted in an increase in the net liability of $158.7 million (December 31, 2007 – $73.1 million) for the underfunded status of the plans, a decrease in deferred tax liability of $53.8 million (December 31, 2007 – $24.8 million) and an increase in accumulated other comprehensive loss of $104.9 million (December 31, 2007 – $48.3 million). As required by FAS 158, the Company adjusted the amounts recognized related to the Canadian pension plans to reflect a December 31 measurement date.*

5 Consolidation of a Limited Partnership

As a result of adopting EITF 04-5, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights, *the Company is consolidating its 27.0% interest in Enbridge Energy Partners for U.S. GAAP purposes, resulting in an increase to both assets and liabilities of $8,248.2 million (December 31, 2007 – $5,932.7 million) and no changes to equity and earnings.*

6 Unrecognized tax benefits

	2008	*2007*
(millions of Canadian dollars)		
Unrecognized Tax Benefits at January 1,	*61.0*	*78.0*
Gross increases for tax positions of current year	*33.4*	*5.0*
Gross decreases for tax positions of prior years	*(82.4)*	*(14.0)*
Changes in translation of foreign currency	*0.8*	*(6.0)*
Settlements during the period	*–*	*(2.0)*
Unrecognized Tax Benefits at December 31,	*12.8*	*61.0*

The unrecognized tax benefits at December 31, 2008, if recognized, would affect the Company's effective income tax rate. Gross increases include a $32.2 million charge for the U.S. tax matter currently under litigation, to unrecognize all of the tax benefits. As an unfavourable court decision was rendered in

2008, the full tax benefit balance of $64.6 was reversed and the unrecognized benefits removed as reflected in gross decreases. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its consolidated financial statements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income tax expense. Income tax expense for the year ended December 31, 2008 includes $1.8 million (2007 – $2.0 million) of interest. As at December 31, 2008, interest and penalties of $8.8 million (2007 – $7.0 million) have been accrued.

The Company and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax, or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2002 and all returns are generally closed through 2003. All U.S. federal income tax returns and generally all U.S. state and local income tax returns are closed through 2004 for all tax matters with the exception of the ongoing tax litigation. U.S. federal income tax returns for 2005 are currently under examination by the Internal Revenue Service.

7 Indefinite reversal rule
We have not provided deferred taxes on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. These earnings relate to ongoing operations and as at December 31, 2008 were approximately $427.6M. It is not practicable to determine, due to the availability of U.S. foreign tax credits, the deferred income tax liability that would be payable if such earnings were not reinvested indefinitely.

NEW ACCOUNTING STANDARDS

Fair Value Measurements

In September 2006, the FASB issued Statement No. 157, Fair Value Measurements. The Statement defines fair value, establishes a framework for measuring fair value in the context of GAAP and expands the disclosure surrounding fair value measurement. In January 2008, the FASB deferred the implementation of this standard for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis, until January 1, 2009. For financial assets and liabilities, the Company has adopted this standard on January 1, 2008.

Fair Value Option for Assets and Liabilities

In February 2007, the FASB issued Statement No. 159, Fair Value Option for Financial Assets and Liabilities. This standard provides companies with an option to measure, at specified election dates, certain financial assets and liabilities at fair value. Changes in fair value are recognized in earnings. The Company has adopted this standard effective January 1, 2008, but has not elected to use the optional fair value measurement.

Future Accounting Standards

The following standards will be effective for the Company beginning on January 1, 2009. Management does not expect the adoption of any of these standards to significantly impact the financial statements.

Business Combinations

In December 2007, the FASB issued Statement No. 141(R), Business Combinations. This Statement retains the fundamental requirements in FAS 141, requiring that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. The Statement revises how the acquisition method is applied when measuring and recognizing certain items acquired.

Accounting for Non-Controlling Interests

In December 2007, the FASB issued Statement No. 160, Non-Controlling Interests in Consolidated Financial Statements. This Statement amends ARB 51 to establish accounting and reporting standards for a non-controlling interest in a subsidiary and for deconsolidation of a subsidiary.

Derivative Instrument and Hedging Activities Disclosures

In March 2008, the FASB issued Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities. This Statement revises disclosure requirements for derivative instruments and hedging activities.

SUPPLEMENTARY INFORMATION (UNAUDITED)

QUARTERLY SHARE TRADING INFORMATION

The Toronto Stock Exchange

2008	First	Second	Third	Fourth
(Canadian dollars)				
High	**42.95**	**46.27**	**45.85**	**43.00**
Low	**36.25**	**41.06**	**37.50**	**33.10**
Close	**42.33**	**44.06**	**39.38**	**39.56**
Volume *(millions)*	**57.8**	**62.4**	**75.7**	**96.6**

2007	First	Second	Third	Fourth
(Canadian dollars)				
High	41.48	38.35	38.74	40.97
Low	36.50	35.21	33.62	35.75
Close	37.66	35.90	36.44	40.01
Volume *(millions)*	60.6	45.8	47.3	50.1

The New York Stock Exchange

2008	First	Second	Third	Fourth
(U.S. dollars)				
High	**43.16**	**46.76**	**44.81**	**38.90**
Low	**35.59**	**40.25**	**35.97**	**26.29**
Close	**41.16**	**43.18**	**38.09**	**32.47**
Volume *(millions)*	**20.5**	**15.6**	**30.3**	**60.2**

2007	First	Second	Third	Fourth
(U.S dollars)				
High	35.40	36.15	37.13	44.29
Low	30.93	32.06	31.26	36.20
Close	32.65	33.78	36.67	40.43
Volume *(millions)*	9.1	11.7	12.6	15.6

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

FINANCIAL AND OPERATING INFORMATION

	2008	2007	2006	2005	2004[1]
(millions of Canadian dollars, except where otherwise noted)					
Earnings Applicable to Common Shareholders					
Liquids Pipelines	**328.0**	287.2	274.2	229.1	219.9
Gas Pipelines	**48.5**	69.7	61.2	59.8	53.8
Sponsored Investments	**111.7**	96.9	86.8	64.8	66.2
Gas Distribution and Services	**300.6**	179.4	173.7	177.0	311.4
International	**608.2**	95.1	83.2	87.4	73.6
Corporate	**(76.2)**	(28.1)	(63.7)	(62.1)	(79.6)
	1,320.8	700.2	615.4	556.0	645.3
Adjusted Earnings [2]	**677.3**	636.5	592.9	537.2	491.1
Cash Flow Data					
Cash provided by operating activities before changes in operating assets and liabilities	**1,398.0**	1,358.0	1,191.6	1,300.9	1,027.8
Cash provided by operating activities	**1,387.7**	1,351.6	1,315.3	947.0	886.7
Additions to property, plant and equipment	**3,635.7**	2,299.2	1,205.9	724.1	496.4
Total Common Share Dividends Declared	**489.3**	452.3	403.1	361.1	315.8
Operating Data					
Liquids Pipelines – Average Deliveries *(thousands of barrels per day)*					
Enbridge System [3]	**2,030**	2,005	2,013	1,872	2,001
Athabasca System [4]	**202**	164	190	142	149
Spearhead Pipeline	**110**	103	82	–	–
Olympic Pipeline	**291**	284	289	–	–
Gas Pipelines – Average Daily Throughput Volume *(millions of cubic feet per day)*					
Alliance Pipeline US	**1,609**	1,598	1,592	1,597	1,581
Vector Pipeline	**1,321**	1,034	1,015	1,033	997
Enbridge Offshore Pipelines	**1,672**	2,060	2,153	2,102	–
Gas Distribution and Services [5]					
Volumes *(billions of cubic feet)*	**444**	450	408	438	575
Number of active customers *(thousands)*	**1,942**	1,902	1,852	1,805	1,756
Degree day deficiency [6]					
Actual	**3,802**	3,659	3,355	3,750	5,052
Forecast based on normal weather	**3,543**	3,617	3,745	3,747	4,849

1 *As a result of the elimination of the quarter lag basis of consolidation, Gas Distribution and Services financial and operating information for 2004 reflects earnings for the 15 months ended December 31, 2004 for Enbridge Gas Distribution, Noverco and other gas distribution entities.*

2 *Adjusted earnings represents earnings applicable to common shareholders adjusted for non-recurring or non-operating factors primarily including non-operating gains and losses, the impact of weather, regulatory disallowances and impacts of tax rate changes. Adjusted earnings is not a measure that has a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and is not considered a GAAP measure; therefore, this measure may not be comparable with similar measures presented by other issuers. Management believes the presentation of adjusted earnings provides useful information to investors and shareholders as it provides increased predictive value and performance trends. Earnings for 2004 have been adjusted to eliminate the quarter lag basis of consolidation described above.*

3 *Enbridge System includes Canadian mainline deliveries in Western Canada and to the Lakehead System at the U.S. border as well as Line 8 and Line 9 in Eastern Canada.*

4 *Volumes are for the Athabasca mainline and the Waupisoo Pipeline and do not include laterals on the Athabasca System.*

5 *Gas Distribution and Services volumes and the number of active customers are derived from the aggregate system supply and direct purchase gas supply arrangements.*

6 *Degree day deficiency is a measure of coldness which is indicative of volumetric requirements of natural gas utilized for heating purposes. It is calculated by accumulating for each day in the period the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto area.*

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

SHAREHOLDER AND INVESTOR INFORMATION

	2008	2007	2006	2005	2004
(per share amounts in dollars)					
Shares Outstanding *(millions)*					
Weighted average common shares outstanding	**359.8**	355.3	340.0	337.4	334.5
Diluted weighted average common shares outstanding	**363.1**	358.3	343.3	341.2	337.2
Common Share Trading (TSX)					
High	**46.27**	41.48	41.45	38.82	30.08
Low	**33.10**	33.62	31.75	28.59	23.63
Close	**39.56**	40.01	40.27	36.34	29.85
Volume *(millions)*	**292.5**	203.8	173.7	211.3	155.4
Per Common Share Information					
Earnings per common share	**3.67**	1.97	1.81	1.65	1.93
Adjusted earnings per common share [1]	**1.88**	1.79	1.74	1.59	1.47
Dividends per common share	**1.32**	1.23	1.15	1.04	0.92
Financial Ratios					
Return on average shareholders' equity [2]	**22.2%**	13.6%	13.9%	13.2%	17.0%
Return on average capital employed [3]	**9.9%**	7.0%	7.0%	6.9%	8.3%
Debt to debt plus shareholders' equity [4]	**66.6%**	66.5%	68.6%	68.9%	67.1%
Earnings coverage of interest [5]	**3.8x**	2.4x	2.4x	2.4x	2.8x
Dividend payout ratio [6]	**70.2%**	68.7%	66.1%	65.2%	62.3%

1 *Adjusted earnings represents earnings applicable to common shareholders adjusted for non-recurring or non-operating factors primarily including non-operating gains and losses, the impact of weather, regulatory disallowances and impacts of tax rate changes. Adjusted earnings is not a measure that has a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and is not considered a GAAP measure; therefore, this measure may not be comparable with similar measures presented by other issuers. Management believes the presentation of adjusted earnings provides useful information to investors and shareholders as it provides increased predictive value and performance trends. Earnings for 2004 have been adjusted to eliminate the quarter lag basis of consolidation described above.*

2 *Earnings applicable to common shareholders divided by average shareholders' equity (weighted monthly during the year).*

3 *Sum of after-tax earnings (including earnings from discontinued operations) and after-tax interest expense, divided by weighted average capital employed. Capital employed is equal to the sum of shareholders' equity, EGD preferred shares, future income taxes, deferred credits and total debt (including short-term borrowings).*

4 *Total debt (including short-term borrowings) divided by the sum of total debt and shareholders' equity.*

5 *Earnings before taxes and interest expenses divided by interest expense (including capitalized interest).*

6 *Dividends per common share divided by adjusted earnings per common share applicable to common shareholders.*

ENBRIDGE BUSINESSES

LIQUIDS PIPELINES

Enbridge Pipelines Inc. (100%)

Enbridge Pipelines (NW) Inc. (100%)

Enbridge Pipelines (Athabasca) Inc. (100%)

Enbridge Pipelines (Toledo) Inc. (100%)

Enbridge Southern Lights LLC (100%)

Enbridge Midstream Inc. (100%)

Gateway Pipeline Limited Partnership (100%)

Mustang Pipe Line Partners (30%)

Chicap Pipe Line Company (43.8%)

Frontier Pipeline Company (77.8%)

CCPS Transportation L.L.C. (Spearhead Pipeline) (100%)

Olympic Pipe Line Company (65%)

Hardisty Caverns Limited Partnership (50%)

GAS PIPELINES

Alliance Pipeline L.P. (U.S. portion) (50%)

Vector Pipeline Limited Partnership (60%)

Enbridge Offshore Pipelines, L.L.C. (22% – 100%)

SPONSORED INVESTMENTS

Enbridge Energy Partners, L.P. (27%)

- Lakehead System
- North Dakota System
- Mid-Continent System
- Various Natural Gas Systems

Enbridge Income Fund (72.3% overall economic interest)

- Enbridge Pipelines (Saskatchewan) Inc. (100%)
- Alliance Pipeline Limited Partnership (Canadian portion) (50%)
- SunBridge Wind Power Project (50%)
- Magrath Wind Power Project (33.3%)
- Chin Chute Wind Power Project (33.3%)
- NRGreen Power Limited Partnership (50%)

GAS DISTRIBUTION AND SERVICES

Enbridge Gas Distribution (100%)

- St. Lawrence Gas Company, Inc.

Gazifere Inc. (100%)

Niagara Gas Transmission Limited (100%)

Noverco Inc. (32.1%), which owns:

- Gaz Métro Limited Partnership (71.0%), which owns:
  - Vermont Gas Systems, Inc. (100%)
  - TQM Pipeline and company, Limited Partnership (50%)
  - Portland Natural Gas Transmission System (38.3%)

Enbridge Gas New Brunswick Limited Partnership (70.9%)

CustomerWorks Limited Partnership (70%)

Enbridge Commercial Services Inc. (100%)

Aux Sable Liquids Products Inc. (42.7%)

Enbridge Gas Services (U.S.) Inc. (100%)

Enbridge Gas Services Inc. (100%)

Tidal Energy Marketing Inc. (100%)

Tidal Energy Markets (U.S.) L.L.C. (100%)

Enbridge Solutions Inc. (100%)

Enbridge Electric Connections Inc. (100%)

Rabaska Limited Partnership (33%)

INTERNATIONAL

Oleoducto Central S.A. (24.7%)

Enbridge Technology Inc. (100%)

CORPORATE

Enbridge Ontario Wind Power Project LP (100%)

NetThruPut Inc. (52%)

FuelCell Energy (strategic alliance)

2008 AWARDS AND RECOGNITION

Alberta's Top 40 Employers: Alberta's Top 40 Employers is an annual competition organized by Mediacorp Canada in partnership with the Human Resources Institute of Alberta. The designation recognizes industry-leading employers in Alberta that offer exceptional places to work.

Canada's Top 100 Employers: Mediacorp Canada again recognized Enbridge as being one of Canada's top employers in 2008. This competition, now in its ninth year, recognizes employers that are industry leaders at attracting and retaining employees. More than 2,000 companies in Canada applied for this year's ranking.

Canadian Standards Association (CSA) Greenhouse Gas (GHG) Registry, Gold Champion Level Reporter: For the third year in a row, the CSA awarded Enbridge's Canadian operations "Gold Level" status for our GHG emissions reporting. Gold is the highest level recognized.

Canadian Utility Fleet Forum E3 Gold Fleet Award: The Fraser Basin Council awarded Enbridge Gas Distribution a Gold Fleet Award for excellence in environmentally friendly fleet management. Enbridge's Ontario fleet is the first commercial fleet to be rated under the Council's E3 Fleet program, and the first fleet ever to receive a Gold Fleet Award.

Conference Board of Canada Carbon Disclosure Leadership Index: Enbridge was ranked third out of 103 Canadian companies that responded to the Carbon Disclosure Project (CDP) questionnaire in 2008. In collaboration with the Conference Board of Canada, the CDP evaluates companies on GHG emissions disclosure, emissions reduction targets, and risk and opportunity identification. Enbridge's high ranking reflects the quality, completeness and comprehensiveness of our climate change disclosures.

Corporate Knights Best 50 Corporate Citizens in Canada: Enbridge ranked as one of Canada's Best 50 Corporate Citizens in Corporate Knights' 2008 ranking.

Dow Jones Sustainability Index (North America): Enbridge Inc. was named to the Dow Jones Sustainability Index North America (DJSI North America) in 2008. The DJSI tracks the financial performance of leading sustainability-driven companies worldwide. The DJSI North America includes the top 20 per cent of companies in each of 57 sectors out of the 600 largest North American companies listed on the Dow Jones Global Index.

EnerQuality Corporation Award of Excellence: EnerQuality Corporation awarded Enbridge Gas Distribution an Award of Excellence for being the Industry Partner of the Year in 2008. Enbridge was recognized for our contributions to sustainable and energy efficient home building.

Fortune America's Most Admired Companies: Enbridge Energy Partners (EEP) ranked fourth among the pipeline companies listed on the 2008 Fortune America's Most Admired Companies list. This is the third year in a row that EEP has been among the top five of the most admired pipeline companies, ranking fourth in 2007 and third in 2006 among its peers.

Governance Metrics International: Governance Metrics International released new ratings and research reports for the 4,200 companies in its system in 2008, and awarded Enbridge an overall global rating of 10.0, the highest rating GMI assigns. Enbridge is one of only 42 companies, or one per cent, to achieve this rating.

Indian and Northern Affairs Canada Aboriginal Relations Award of Distinction: Indian and Northern Affairs awarded Enbridge its Aboriginal Relations Award of Distinction at the annual Alberta Business Awards in 2008.

United Nations Global Compact Award: The Calgary Chapter of the United Nations Association of Canada presented Enbridge with the 2008 United Nations Global Compact Award in 2008. This award recognizes Enbridge's local and international leadership and demonstrated track record in corporate social responsibility.

INVESTOR INFORMATION

Common and Preferred Shares

The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange under the trading symbol "ENB". The Preferred Shares, Series A, of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbol "ENB.PR.A".

Registrar and Transfer Agent in Canada

CIBC Mellon Trust Company
P.O. Box 7010,
Adelaide Street Postal Station
Toronto, Ontario M5C 2W9
Toll free: (800) 387-0825
Internet: www.cibcmellon.com/investorinquiry
CIBC Mellon Trust Company also has offices in Halifax, Montreal, Calgary and Vancouver.

Co-Registrar and Co-Transfer Agent in the United States

BNY Mellon Shareowner Services
480 Washington Blvd.
Jersey City, New Jersey
U.S.A. 07310
Toll free: (800) 387-0825
Internet: www.cibcmellon.com/investorinquiry

Debentures and Notes — Registrars and Trustees:

The registrar and trustee for Enbridge Debentures is Computershare Trust Company of Canada, with offices in Montreal, Toronto, Winnipeg, Calgary, Halifax and Vancouver.

Auditors

PricewaterhouseCoopers LLP

Dividend Reinvestment and Share Purchase Plan, and Dividend Direct Deposit

Enbridge Inc. offers a Dividend Reinvestment and Share Purchase Plan that enables shareholders to reinvest their cash dividends in Common Shares and to make additional cash payments for purchases at the market price. Effective with dividends payable on March 1, 2008, participants in the Plan will receive a two per cent discount on the purchase of common shares with reinvested dividends. The Company also offers Dividend Direct Deposit which enables shareholders to receive dividends by electronic fund transfer (EFTS) to the bank account of their choice in Canada. Details may be obtained from the Investor Information section of the Enbridge website at or by contacting CIBC Mellon Trust Company at any of the locations listed above.

New York Stock Exchange Disclosure Differences

As a foreign private issuer, Enbridge Inc. is required to disclose any significant ways in which its corporate governance practices differ from those followed by U.S. companies under NYSE listing standards. This disclosure can be obtained from the U.S. *Compliance* subsection of the *Corporate Governance* section of the Enbridge website at www.enbridge.com.

Form 40-F

The Company files annually with the U.S. Securities and Exchange Commission a report known as the Annual Report on Form 40-F. Copies of the Form 40-F are available, free of charge, upon written request to the Corporate Secretary of the Company. In addition a link to it is available on the "Reports and Filings" subsection of the "Financial Reports" section of our website.

Corporate Social Responsibility Report

Enbridge publishes an annual Corporate Social Responsibility report. The 2008 report is available on the Company's website at www.enbridge.com/csr2008

Registered Office

Enbridge Inc.
3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 231-3900
Facsimile: (403) 231-3920
Internet: www.enbridge.com

Shareholder Inquiries

If you have inquiries regarding the following:

- Dividend Reinvestment and Share Purchase Plan
- change of address
- share transfer
- lost certificates
- dividends
- duplicate mailings

Please contact the registrar and transfer agent–CIBC Mellon Trust Company in Canada or BNY Mellon Shareowner Services in the United States.

Other Investor Inquiries

If you have inquiries regarding the following:

- additional financial or statistical information
- industry and company developments
- latest news releases or investor presentations
- any other investment related inquiries

Please contact Enbridge Investor Relations or visit Enbridge's website at www.enbridge.com.

Investor Relations

Enbridge Inc.
3000, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Toll free: (800) 481-2804

Annual Meeting

The Annual Meeting of Shareholders will be held at Le Royal Meridien King Edward Hotel, Toronto, Ontario at 1:30 p.m. EDT on Wednesday, May 6, 2009. A live webcast of the meeting will be available at www.enbridge.com and will be archived on the site for approximately one year. Webcast details will be available on the company's website closer to the meeting date.

Le présent document est disponible en français.

2009 Dividend Information for Common Shares and Preferred Shares, Series A [1]

	1st Q	2nd Q	3rd Q	4th Q
Record date	Feb. 16	May 15	Aug. 17	Nov. 16
Payment date	Mar. 1	Jun. 1	Sep. 1	Dec. 1
Common Share Dividend Reinvestment Plan (DRIP) enrolment cut-off date	Feb. 9	May 8	Aug. 10	Nov. 9
Common Share Purchase Plan cut-off date for DRIP	Feb. 23	May 25	Aug. 25	Nov. 24

1 *Dividend dates are subject to the dividends being declared by the Board of Directors.*

ENBRIDGE*

Enbridge Inc. is a leader in energy transportation and distribution in North America and internationally. Our key objective is to generate superior shareholder value. In Canada and the United States, we operate the world's longest crude oil and liquids transportation system. We own and operate Canada's largest natural gas distribution company. We have growing involvement in natural gas transmission and midstream businesses throughout North America. We are investing in renewable and alternative energy initiatives as well as international energy projects. Enbridge employs approximately 6,000 people in Canada, the U.S. and South America.

Enbridge's common shares trade on the Toronto Stock Exchange in Canada and on the New York Stock Exchange in the U.S. under the symbol ENB.

www.enbridge.com

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